CITIPOWER PTY

REVISED REGULATORY PROPOSAL: 2011 TO 2015

21 JULY 2010

CONTENTS

CitiPower's Regulatory Proposal 2011-15 - Glossary

Term	Description
2001-05 Negative Carryover	Powercor Australia's negative efficiency carryover of -$22.9 million (in $2004) arising in the 2001-05 regulatory period
2005 Line Clearance Code	*Code of Practice for Electric Line Clearance 2005*
2005 Line Clearance Regulations	*Electricity Safety (Electric Line Clearance) Regulations 2005*
2009 TCPR	Victorian DNSPs, Transmission Connection Planning Report Produced jointly by the Victorian Electricity Distribution Businesses, 2009
2010 Line Clearance Code	*Code of Practice for Electric Line Clearance 2010*
2010 Line Clearance Regulations	*Electricity Safety (Electric Line Safety) Regulations 2010*
2016-20 Distribution Determination	The future distribution determination it is anticipated will be made by the AER for the 2016-20 regulatory control period.
ABS	Australian Bureau of Statistics
Access Economics	Access Economics Pty Ltd (ACN 123 967 966)
ACG	Allen Consulting Group Pty Ltd (ABN 52 007 061 930)
ACIL Tasman	ACIL Tasman Pty Ltd (ABN 68 102 652 148)
ACR	Auto Circuit Recloser
ACT	Australian Capital Territory
ACT Final Determination	The AER's Final Decision Australian Capital Territory distribution determination 2009-10 to 2013-14 dated 28 April 2009
AEMC	Australian Energy Market Commission

Term	Description
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AH	After business hours
AMI	Advanced Metering Infrastructure
AMI Order in Council	The Orders in Council made by the Victorian Government under sections 15A and 46D of the Electricity Industry Act in respect of AMI on 28 August 2007 (published in the Victorian Government Gazette S200), 12 November 2007 (Victorian Government Gazette s286), 25 November 2008 (Victorian Government Gazette S314) and 31 March 2009 (Victorian Government Gazette G14)
AMRS	AMRS (Aust) Pty Ltd (ABN 11 098 326 179)
Annual Planning Report	The 'Distribution System Annual Planning Report' that a Victorian DNSP is required to prepare annually in accordance with clause 3.5 of the Distribution Code
Aon	Aon Risk Services Australia Limited (ABN 17 000 434 720)
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency (ABN 61 321 195 155)
ARR	Annual Revenue Requirement
AS	Australian Standards
ASIC	Australia Standard Industrial Classification
ASX	ASX Limited (ABN 98 008 624 691)
ATO	Australian Tax Office
avoided DuOS payments	The payments that the DNSP is required to make to embedded generators under the ESCV's Guideline 15
avoided TuOS payments	The payments that the DNSP is required to make to embedded generators under clause 5.5(h) of the Rules
AWE	Average weekly earnings
AWOTE	Average weekly ordinary time earnings
AWTE	Average weekly total earnings (i.e. including overtime) of full-time and part-time employees
B2B	Business-to-Business
BH	Before business hours
BIS Shrapnel	BIS Shrapnel Pty Limited (ABN 20 060 358 689)
bppa	Basis points per annum
Bushfires Royal Commissi	2009 Victorian Bushfires Royal Commission established on 16 February 2009 to investigate the causes and responses to the bushfires which swept through parts of Victoria in late January and February 2009

Term	Description
on	
CAGR	Cumulative Average Growth Rate
CAM	Cost Allocation Methodology
capex	Capital expenditure
capex criteria	The capital expenditure criteria prescribed by clause 6.5.7(c) of the Rules
capex objectives	The capital expenditure objectives set out in clause 6.5.7(a) of the Rules
CBRM	Condition Based Risk Management
CEG	Competition Economists Group
CEPU	Communications, Electrical and Plumbing Union
CGS	Commonwealth Government Securities
CHED Services	CHED Services Pty Ltd (ABN 14 112 304 622)
CHEDHA	CKI/HEH Electricity Distribution Holdings (Australia) Pty Ltd (ABN 68 101 392 161)
CIC	Capital Investment Committee
CIS	Customer Information System
CitiPower	CitiPower Pty (ABN 76 064 651 056)
CitiPower 2008 Regulatory Accounts	CitiPower's regulatory accounts for the year ended 31 December 2008
CitiPower 2009 Regulatory Accounts	CitiPower's regulatory accounts for the year ended 31 December 2009
CKI	Cheung Kong Infrastructure Holdings Ltd
CoF	Consequence of Failure
Contribution Rate	The proportion of customer contributions to new customer connections capex
Corporate Communications Agreement	The agreement of this name entered into with Silk Telecom and dated 26 May 2008 under which Silk Telecom provides corporate communications services including managed WAN, WAN links, mobile phones, remote access and PABX, voice and data communications
Corporate Services Agreemen	The agreement of titled 'CitiPower 2008-2010 Services Agreement' entered into with CHED Services in January 2008 under which CHED Services provides specialist corporate services, including the Chief Executive Officer, Finance, the Company Secretary, Legal, Human Resources, Corporate Affairs, Regulation, Customer Services, Information Technology and

Term	Description
t	Office Administration
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSIRO	Commonwealth Scientific and Research Organisation
Current Regulatory Proposal	Powercor Australia's Initial Regulatory Proposal as revised by this Revised Regulatory Proposal
Deloitte	Deloitte Touche Tohmatsu
Distribution Code	ESCV's Electricity Distribution Code Version 4 dated February 2010
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DPI	Victorian Department of Primary Industries
Draft Determination	The AER's Draft Decision Victorian electricity distribution network service providers Distribution determination 2011-15 dated 4 June 2010
Draft GAAR	The ESCV's Gas Access Arrangements Review 2008-12: Draft Decision of August 2007
DRMF	Distribution Reliability Management Framework
DRMS	Discretionary Risk Management Scheme
DRP	Debt Risk Premium
DSE	Victorian Department of Sustainability and Environment
DSPR	Distribution System Planning Report
DuOS	Distribution Use of Service
EA Technology	EA Technology Ltd
EBA	Enterprise Bargaining Agreement
EBIT	Earnings before interest and tax
EBSS	The efficiency benefit sharing scheme developed and published by the AER under clause 6.5.8 of the Rules as amended from time to time
EBSS Final Decision	The AER's Final decision Electricity distribution network service providers efficiency benefit sharing scheme, dated 26 June 2008
EBSS	Efficiency Benefit Sharing Scheme published by the AER on 26 June 2008 in accordance with

Term	Description
Guideline	section 6.5.8 of the Rules (set out in Appendix E to the EBSS Final Decision)
ECM	Efficiency Carryover Mechanism
EDPR	Electricity Distribution Price Review
EGW	The Electricity, Gas, Water and Waste Services industry
ElectraNet	Electranet Pty Limited (ABN 41 094 482 416)
Electrical Network Communications Agreement	Electrical Network Communications Agreement – The agreement of this name entered into with Silk Telecom and dated 26 May 2008 under which Silk Telecom provides electrical services including SCADA and Trunked Mobile Radio Services
Electricity Industry Act	*Electricity Industry Act 2000* (Vic)
Electricity Safety Act	*Electricity Safety Act 1998* (Vic)
Electricity Safety Management Regulations	*Electricity Safety (Management) Regulations 2009* (Vic)
Electricity System Code	ORG, Electricity System Code, October 2000
ELV	Electric Light Vehicle
Energex	ENERGEX Ltd
Energy Response	Energy Response Pty Ltd (ABN 49 104 710 278)
EPA	Environmental Protection Authority (ABN 85 899 617 894)
Ernst & Young	Refers to one or more of the member firms of Ernst & Young Global Limited, a UK private company limited by guarantee
ESAA	Electricity Supply Association of Australia Pty Ltd (ACN 071 949 329)
ESC Act	*Essential Services Commission Act 2001* (Vic)
ESCV	Essential Services Commission of Victoria
ESCV Appeal Panel	Appeal Panel established under section 56 of the ESC Act
ESCV Appeal	Reasons for Decision of Appeal Panel in appeal by CitiPower dated 17 February 2006, Panel

Term	Description
Panel Decision	reference: E6/2005
ESCV Credit Decision	ESCV, Credit Support Arrangements, Final Decision, October 2006
ESCV's 2006-10 EDPR	Collectively refers to ESCV, *Electricity Price Review 2006-10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final decision Volume 1, Statement of Purpose and Reasons* and *Final Decision Volume 2 Price Determination (October 2005 Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006 and an Order in Council under section 15A and 46D of the Electricity Industry Act 2000 (28 August 2007) as amended on 25 November 2008),* both dated December 2008
ESCV's Guideline 14	Electricity Industry Guideline No. 14 Provision of Services by Electricity Distributors Issue 1, April 2004
ESCV's Guideline 15	Electricity Industry Guideline No. 15 Connection of Embedded Generation Issue 1, August 2004
ESCV's Security of Supply Decision	ESCV, Final Decision, CBD Security of Supply, February 2008
ESMP	Electrical Safety Management Plans
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria (ABN 27 462 247 657)
ETSA	ETSA Utilities (ABN 13 332 330 749)
EWOV	Energy and Water Ombudsman (Victoria)
EWP	Elevated Work Platform
Extreme Supply Events Decision	The ESCV's Final Decision Electricity Distributors' Communications in Extreme Supply Events, dated December 2009
Final Customer Contributions Decision	The AER's Conclusion on the Benchmark Upstream Augmentation Charge Rates for CitiPower's Network, 25 June 2010
Final Determination	The AER's impending final distribution determination for CitiPower in respect of the 2011-15 regulatory control period
Final Determina	The AER's impending final distribution determinations for the Victorian DNSPs in respect of the

Term	Description
tions	2011-15 regulatory control period
Framework and Approach Paper	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 dated 29 May 2009
FRC	Full retail contestability
Frontier	Frontier Economics Pty Ltd (ABN 13 087 553 124)
Further RIN	The Regulatory Information Notice dated 4 June 2010 issued to CitiPower by the AER under s28F(1)(a) of the NEL
GAAR	The ESCV's Gas Access Arrangement Review 2008-2012: Final Decision dated March 2008
GDP	Gross domestic product
GFC	Global financial crisis
GIS	Geographic Information System
GSL	Guaranteed Service Level
GSP	Gross State Product
GWh	Gigawatt Hour
GWM Water	Grampians-Wimmera-Mallee Water
Hays	Hays Specialist Recruitment (Australia) Pty Limited (ABN 47 001 407 281)
HBRA	Hazardous Bushfire Risk Area
HEH	HongKong Electric Holdings Ltd
HEI	HongKong Electric International Limited
Henry Review	The Australia's Future Tax System Review established by the Rudd Government in 2008 to examine Australia's tax and transfer system, including state taxes, and make recommendations to position Australia to deal with the demographic, social, economic and environmental challenges of the 21st century
HI	Health Index
HV	High Voltage
HV Protection Sub-Code	High Voltage Protection Sub-Code, July 2008
IHDs	In home energy displays
Impaq	Impaq Consulting Pty Ltd (ABN 41 005 127 659)
Initial Regulatory Proposal	CitiPower's regulatory proposal for the regulatory control period 1 January 2011 to 31 December 2015 for distribution services provided by means of, or in connection with, its distribution system submitted to the AER on 30 November 2009 in accordance with clause 6.8.2 of the Rules

Term	Description
Initial Regulatory Templates	The completed regulatory templates submitted by Powercor Australia to the AER as part of its Initial Regulatory Proposal in response to clause 1 of Schedule 1 to the Initial RIN
Initial RIN	The regulatory information notice issued to Powercor Australia by the AER on 13 October 2009 under section 28F(1)(a) of the NEL
Inter-DNSP charges	The inter-network provider distribution service tariffs paid to other DNSPs (net of any similar payments received from other DNSPs)
IT	Information Technology
Jackgreen	Jackgreen (International) Pty Ltd (ABN 14 097 708 104)
Jemena	Jemena Electricity Networks (VIC) Ltd (ABN 82 064 651 083)
Jemena Gas	Jemena Gas Networks (NSW) Ltd (ABN 87 003 004 322)
Jemena Gas Access Draft Decision	The AER's Draft decision - public Jemena Access arrangement proposal for the NSW gas networks 1 July 2010 - 30 June 2015 dated 10 February 2010
Jemena Gas Access Final Decision	The AER's Final Decision - public Jemena Gas Networks Access arrangement proposal for the NSW gas networks 1 July 2010-30 June 2015 dated 11 June 2010
km	Kilometre
KPI	Key Performance Indicator
KPMG	KPMG Econtech Pty Limited (ACN 003 591 008)
kV	Kilovolts
kVA	Kilovolt Amperes
LBRA	Low bushfire risk area
LCM	Labour Cost Model
LGA	Local Government Areas
LIDAR	vegetation line clearance inspection audit
Lighting RIS	Regulatory Impact Statement for Decision – Proposed MEPS for incandescent lamps, compact fluorescent lamps and voltage converters, 2009
Line Clearance RIS	Regulatory Impact Statement for Decision - Proposed Electricity Safety (Electric Line Safety) Regulations 2010
LLV	Large Low Voltage

Term	Description
LPI	Labour Price Index
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
March 2010 Regulatory Templates	The version of the Initial Regulatory Templates updated for currency submitted by Powercor Australia to the AER on 4 March 2010
Maunsell	Maunsell Australia Pty Ltd
MAV	Municipal Association of Victoria (ABN 24 326 561 315)
MCE	Ministerial Council on Energy
MCR	Marginal Cost of Reinforcement
MDS	Metering Data Services
MEC	Major Electricity Company
MED	Major event day
MEPS	Minimum Energy Efficiency and Performance Standards for appliances
Mercer	Mercer (Australia) Pty Ltd (ABN 32 005 315 917)
MRET	Mandated Renewable Electricity Target
MRIM	Manually Read Interval Meters
MRP	Market risk premium
MSATS	Market Settlement and Transfer Solution
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited (now AEMO)
NEO	The national electricity objective set out in section 7 of the NEL
NERA	National Economic Research Associates, Inc
NERG	Network Extensions for Remote Generation
Network Services Agreement	The agreement titled 'CitiPower 2008-2010 Services Agreement' entered into with PNS in 2008 under which PNS provides construction and maintenance services, including customer and connection services, asset replacement maintenance services, asset performance (fault services) and network development services
NEVA	*National Electricity (Victoria) Act 2005* (Vic)

Term	Description
NIEIR	National Institute of Economic and Industry Research (ABN 72 006 234 626)
NMI	National Metering Identifier
Norfolk	Norfolk Group Limited (ABN 43 125 709 971)
NPV	Net Present Value
NSW	New South Wales
NSW Draft Determination	The AER's Draft Decision New South Wales distribution determination 2009-10 to 2013-14 dated 21 November 2008
NSW Final Determination	The AER's Final Decision New South Wales distribution determination 2009-10 to 2013-14 dated 28 April 2009
Officer CAPM Framework	The Capital Asset Pricing Model framework developed by Professor Bob Officer
Ofgem	United Kingdom's Office of Gas and Electricity Markets
OHS	Occupational Health and Safety
OMS	outage management systems
opex	Operating and maintenance expenditure
opex criteria	The operating expenditure criteria prescribed by clause 6.5.6(c) of the Rules.
opex objectives	The operating expenditure objectives set out in clause 6.5.6(a) of the Rules.
ORG	Office of the Regulator General
ORG Appeal Panel	ORG Appeal Panel established under section 38 of *Office of Regulator-General Act 1994*
ORG Appeal Panel Decision	ORG Appeal Panel, 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
ORG's 2001-05 EDPR	ORG, Electricity Distribution Price Determination 2001-05, Volume 1, Statement of Purpose and Reasons, September 2000
ORPs	Other responsible persons
PABX	Private Automated Branch Exchange
PAPL	Permitted Attached Private Lines
PB	Parsons Brinckerhoff Strategic Consulting

Term	Description
PDM	Program of Demand Management
PFIT Payments	Payments under premium feed-in tariff schemes
PFIT Rule Change	AEMC Rule Determination and new rule for Payments under Feed-in Schemes and Climate Change Funds
Plan	Electric Line Clearance Management Plan
PNS	Powercor Network Services Pty Ltd (ABN 94 123 230 24)
PNS' 2009 Regulatory Accounts	PNS' financial statements for the year ended 31 December 2009
PoE	Probability of Exceedance
POEL	Private Overhead Electric Line
PoF	Probability of Failure
Powercor Australia	Powercor Australia Limited (ABN 89 064 651 109)
Powercor Australia's 2008 Regulatory Accounts	Powercor Australia's regulatory accounts for the year ended 31 December 2008
Powercor Australia's 2009 Regulatory Accounts	Powercor Australia's regulatory accounts for the year ended 31 December 2009
Powercor Australia's Cost Allocation Methodolo gy	Powercor Australia's cost allocation methodology approved by the AER in accordance with caluse 6.15.4 of the Rules
Previous Distributio n Determina tions	Collectively refers to the AER's ACT Final Determination, NSW Final Determination, Queensland Final Determination and South Australian Final Determination
Proclaime d Fire Danger Period	The fire danger period in respect of the country area of Victoria or any part thereof that is declared pursuant to the *Country Fire Act 1958* (Vic) to be a fire danger period in respect of the said country area or part thereof.
Proposed	The AER's Proposed Electricity transmission and distribution network service providers

Term	Description
SoRI	Statement of the revised WACC parameters (transmission) Statement of regulatory intent of the revised WACC parameters (distribution) dated 11 December 2008
PTRM	Post Tax Revenue Model
Public Lighting Decision	The AER's Energy Efficient Public Lighting Charges - Victoria Final Decision dated 27 February 2009
PV	Photovoltaic
PwC	PricewaterhouseCoopers (ABN 52 780 433 757)
Queensland Final Determination	The AER's Final decision Queensland distribution determination 2010-11 to 2014-15 dated 6 May 2010
Queensland Framework and Approach Paper	The AER's Framework and Approach Paper, classification of services and control mechanisms, Energex and Ergon Energy 2010-15, Final Decision, dated August 2008
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia (ABN 50 008 559 486)
RCM	Reliability Centred Maintenance
RECs	Renewable Energy Certificates
Regulatory control period	Takes its defined meaning as set out in Chapter 10 of the Rules
Repex Model	The AER's replacement capex forecasting model developed on its behalf by its consultant, Nuttall Consulting.
RET	Renewable Energy Target
Revenue and pricing principles	The revenue and pricing principles set out in section 7A of the NEL.
Revised Regulatory Proposal	This document, its appendices and attachments, which together comprise: Powercor Australia's revised regulatory proposed in response to the Draft Determination for the purposes of clause 6.10.3 of the Rules; Powercor Australia's submission in response to the Draft Determination; and Powercor Australia's response to the Further RIN dated 4 June 2010.
Revised Regulatory Templates	The completed regulatory templates submitted to the AER by Powercor Australia as part of its Revised Regulatory Proposal in response to clause 1 of Schedule 1 to the Further RIN

Term	Description
RIN	Regulatory Information Notice
RIS	Regulatory Impact Statement
RIT-D	Regulatory Investment Test – Distribution
RoLR	Retailer of Last Resort
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCO	Standing Committee of Officials of the Ministerial Council on Energy
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
SECV	State Electricity Commission of Victoria (ABN 58 155 836 293)
SEPPs	State Environment Protection Policies
SFG	Strategic Finance Group: SFG Consulting
Silk Telecom	Silk Telecom Pty Ltd (ABN 96 095 420 616)
SKM	Sinclair Knight Merz Pty Limited (ABN 37 001 024 095)
SMS Consulting	SMS Consulting Group Ltd (ABN 17 006 515 028)
SOO	Statement of Opportunities
SoRI	The AER's Electricity transmission and distribution network service providers Statement of the revised WACC parameters (transmission) Statement of regulatory intention on the revised WACC parameters (distribution) dated 1 May 2009
SoRI Final Decision	The AER's Electricity transmission and distribution network service providers' review of the weighted average cost of capital (WACC) parameters dated 1 May 2009.
South Australian Final Determination	The AER's Final decision South Australia distribution determination 2010-11 to 2014-15 dated 4 May 2010
South Australian Draft Determination	The AER's Draft decision South Australia Draft distribution determination 2010-11 to 2014-15 dated 25 November 2009
South Australian Framewor	The AER's Framework and Approach Paper ETSA Utilities 2010-15 Final Decision, dated November 2008

Term	Description
k and Approach Paper	
SP AusNet	SPI Electricity Pty Ltd (ABN 91 064 651 118)
SP AustNet Draft Transmission Determination	The AER's Draft decision SP AusNet transmission determination 2008-09 to 2013-14 dated 31 August 2007
SP AustNet Final Transmission Determination	The AER's Final decision SP AusNet transmission determination 2008-09 to 2013-14 dated January 2008
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
Tariff Order	The Victorian Electricity Supply Industry Tariff Order 2005, made under section 15A of the Electricity Industry Act
TMR	Trunk Mobile Radio
TNSP	Transmission Network Service Provider
TOU Tariffs	Time of use tariffs
Trade Practices Act	*Trade Practices Act 1974* (Cth)
Transmission connection charges	The charges payable by DNSPs for connection to the transmission system
Transmission-related Costs	Collectively refers to transmission connection charges, inter-DNSP charges, avoided TuOS payments and avoided DuOS payments
Tribunal	The Australian Competition Tribunal
TuOS	Transmission Use of System
UED	United Energy Distribution Pty Ltd (ABN 70 064 651 029)
ULLS	The ACCC's assessment of Telstra's Unconditioned Local Loop Service Bank 2 monthly

Term	Description
Final Decision	charge undertakings, Final Decision dated 28 April 2009
UoSA	Use of Systems Agreement
URD	Underground Residential Developments
USAIDI	Unplanned System Average Interruption Duration Index
VCR	Value of Customer Reliability
VEECs	Victorian Energy Efficiency Certificates
VEET	Victorian Energy Efficiency Target
VEMCO	VEMCO Pty Limited (ABN 43 065 985 453)
VENCorp	Victorian Energy Networks Corporation Pty Ltd (ACN 081 026 066)
VF	Voice Frequency
Victorian DNSPs	CitiPower, Powercor Australia, Jemena, SP AusNet and UED
VoIP	Voice over internet protocol
WACC	Weighted Average Cost of Capital
WAN	Wide area network.
WAPC	Weighted Average Price Control
WDV	Written Down Value
Wilson Cook	Wilson Cook & Co Limited
WMTS	West Melbourne Terminal Station

1. INTRODUCTION AND EXECUTIVE SUMMARY

1.1 Introduction

On 30 November 2009, CitiPower submitted its Initial Regulatory Proposal for the regulatory control period 1 January 2011 to 31 December 2015 to the AER in accordance with clause 6.8.2 of the Rules.

The AER published its Draft Determination in accordance with clauses 6.10.1 and 6.10.2 of the Rules on 4 June 2010.

This document and its appendices and attachments together comprise CitiPower's Revised Regulatory Proposal. This Revised Regulatory Proposal contains:

- CitiPower's revised regulatory proposal in response to the Draft Determination for the purposes of clause 6.10.3 of the Rules;
- CitiPower's submission in response to the Draft Determination; and
- CitiPower's response to the Further RIN issued by the AER under s28F(1)(a) of the NEL on 4 June 2010.

This Revised Regulatory Proposal has been prepared in response to the matters raised in the AER's Draft Determination.

In this Revised Regulatory Proposal, CitiPower has made revisions to its Initial Regulatory Proposal to incorporate the substance of any changes required to address matters raised by the Draft Determination or the AER's reasons for it. As already observed, this Revised Regulatory Proposal also contains CitiPower's submission in response to the AER's Draft Determination and its response to the Further RIN.

This Revised Regulatory Proposal has been prepared in accordance with clauses 6.10.2(c) and 6.10.3 of the Rules.

CitiPower's response to the Further RIN contained in the Revised Regulatory Proposal has been prepared in accordance with the requirements of that RIN, as modified by subsequent correspondence from the AER. In particular, by email dated 21 June 2010, the AER extended the date for lodgement by CitiPower of its response to the Further RIN to 21 July 2010 in order to align the lodgement date for the Further RIN response with the time for lodgement of the Revised Regulatory Proposal established by clause 6.10.3(a) of the Rules.[1]

1.2 Executive summary

CitiPower is disappointed with the AER's Draft Determination. It considers that the AER's Draft Determination:

[1] Email from P Dunn, Director, AER to B Cleeve, General Manager Price Review, CitiPower and Powercor Australia, 'Extension of submission date for the RIN', dated 21 June 2010.

- may compromise the reliability of supply to Victorian consumers of electricity, and the safe operation of its distribution network and resultant safety of the Victorian public;
- is inconsistent with Previous Distribution Determinations and cannot be reconciled with the AER's own and CitiPower's consultants' benchmarking of its relative efficiency; and
- effects a fundamental reassignment of risk between DNSPs and customers through the decisions on pass through and the recovery of Transmission-related Costs.

The AER's reduction of CitiPower's capex program by 46 per cent will have adverse implications for Victorian electricity consumers and the Victorian public, as the AER's Draft Determination compromises CitiPower's ability to:

- maintain the reliability of supply by, and safety of, its ageing distribution network; and
- continue to deliver distribution network services efficiently in the long term.

CitiPower is concerned that the AER's reductions to its capex program may reflect a lack of understanding of that program. Accordingly, this Revised Regulatory Proposal seeks to clarify CitiPower's proposed capex program by reference to the information, documents and material already adduced, as well as by adducing further information, documents and material in support of that program.

CitiPower is also disappointed by the lack of consistency in distribution regulatory decision making by the AER. CitiPower considers that the AER's decision making process, its methodologies and approach adopted in the Draft Determination and the price outcome from its Draft Determination represent a significant departure from the AER's approach in making Previous Distribution Determinations for New South Wales, Queensland and South Australia.

The relative price outcomes in the AER's Draft Determination and in the AER's Previous Distribution Determinations for New South Wales, Queensland and South Australia also stand in marked contrast to the results of benchmarking analysis of the DNSPs in these jurisdictions. The Draft Determination prescribes a significant reduction in distribution charges for standard control services in Victoria in 2011 and negligible price changes in subsequent years of the regulatory control period. By contrast, the AER's Previous Distribution Determinations for New South Wales, Queensland and South Australia all allowed significant price increases in the opening year of the relevant regulatory control period and material price increases in subsequent years. These relative price outcomes are difficult to reconcile with the results of benchmarking analysis which indicate that Victorian DNSPs, and CitiPower in particular, operate on the efficiency frontier. In particular:

- the AER concluded, on the basis of its own capex benchmarking, that *'Victorian DNSPs compare well when overall capex is compared with that of Queensland and NSW'* and *'the overall level of capex for the Victorian DNSPs is broadly below the level of comparable DNSPs'*;[2]
- the AER concluded, on the basis of its own opex benchmarking, that *'Victorian DNSPs compare well when overall opex is compared with that of Queensland and NSW'*, *'the overall level of opex for the Victorian DNSPs is broadly below the level of comparable DNSPs'* and *'Victorian DNSPs appear relatively efficient compared to other non-Victorian DNSPs'*;[3] and
- CitiPower and Powercor Australia engaged NERA to benchmark the relative efficiency of their opex forecasts for 2011-15 set out in their Initial Regulatory Proposals vis-à-vis 11 other DNSPs operating in the NEM and Western Australia and NERA concluded that CitiPower was the most efficient, and Powercor Australia the second most efficient, of the 13 DNSPs examined by it.[4]

Yet, the AER provided in the Draft Determination for a significant reduction to what it has conceded is efficient Victorian DNSP pricing, despite having previously allowed significant price increases for the relatively inefficient DNSPs in New South Wales, Queensland and South Australia.

Finally, CitiPower is concerned by the fundamental reassignment of risk between DNSPs and customers, with DNSPs bearing a greater burden of the risk, effected by:

- The materiality threshold specified in the Draft Determination for nominated pass through events and the AER's rejection of the financial failure of a retailer nominated pass through event. Currently in Victoria under the ESCV's 2006-10 EDPR, the 'materiality threshold' for pass through events is a 'material financial impact on the distribution business' and the financial failure of a retailer event is a defined pass through event.
- The AER's failure to provide a mechanism in the Draft Determination for the recovery of charges payable by CitiPower for connection to the transmission system, inter-DNSP tariffs (net of any similar payments received from other DNSPs) and payments to embedded generators in respect of avoided TuOS and DuOS payments, collectively referred to in this Revised Regulatory Proposal as Transmission-related Costs. Currently in Victoria, the ESCV's 2006-10 EDPR provides a mechanism for the full recovery of these Transmission-related Costs by Victorian DNSPs.

Victorian DNSPs must be compensated through regulated revenues for any increase in the risks allocated to them under the AER's Final Determination as compared to the ESCV's 2006-10 EDPR. The AER has not provided any

[2] AER, Draft Determination Appendices, Appendix I, pp60-1.
[3] AER, Draft Determination Appendices, Appendix I, pp68, 69 and 74.
[4] NERA, Review of Operating Expenditure Efficiency, July 2010 (Attachment 102 to this Revised Regulatory Proposal).

compensation for DNSPS for carrying this additional risk. It has not allowed any additional expenditure through self insurance or opex because both of these are based on revealed 2009 costs. Nor has the AER amended its calculation of WACC to allow a premium for managing this additional risk.

In the remainder of this executive summary, CitiPower:

- outlines a number of concerns it has with the AER's approach to date to making its Final Determination, in section 1.2.1 below; and
- provides a summary of its response in this Revised Regulatory Proposal to specific aspects of the AER's Draft Determination with which CitiPower takes issue, in section 1.2.2 below.

1.2.1 Response to AER's approach in Draft Determination

As foreshadowed above, CitiPower has concerns with a number of aspects of the AER's approach to date to the making of its Final Determination. These concerns relate either to the procedure adopted by the AER in its decision making or its assessment of various aspects of the Initial Regulatory Proposal.

1.2.1.1 Inconsistency with Previous Distribution Determinations and decision making processes

CitiPower is concerned by the lack of consistency in the AER's procedure and approach to making its Final Determination with the procedure and approach to making its Previous Distribution Determination in the ACT, NSW, Queensland and South Australia.

CitiPower maintains that consistency in decision making was, and remains, a core objective of the establishment of a national framework for distribution economic regulation and is a characteristic of good administrative decision making.

However, in making its Draft Determination, the AER has made a number of significant departures from the procedure and approach it adopted in making its Previous Distribution Determinations. Notable examples include the following:

- In assessing CitiPower's forecast of reinforcement capex, the AER has adopted forecasts prepared by Nuttall Consulting using a model that is 'novel', particularly insofar as it is subjective and heavily dependent on 'judgment'. It has not been applied in any Previous Distribution Determination or any previous determination by the ESCV. As a result, it is an untested approach to forecasting reinforcement capex. Perhaps because of this, Nuttall Consulting's forecasting methodology and the assumptions underpinning its approach are flawed. In particular:
    - the forecasts are not linked to maximum demand forecasts. That is, its forecasts of reinforcement capex do not reflect any explicit consideration of maximum demand; and
    - Nuttall Consulting's determination of the probability of CitiPower's reinforcement capex projects going ahead, which is a

critical determinant of Nuttall Consulting's forecast of CitiPower's reinforcement capex, is based entirely on 'judgment' resulting in a forecast of reinforcement capex that is, in turn, qualitative and subjective.

- In assessing CitiPower's forecast capex for 2011-15 in its Draft Determination, the level of engagement by the AER and its consultant, Nuttall Consulting, is in marked contrast to that experienced by ETSA in its distribution price review. CitiPower understands that, in the South Australian distribution price review, the AER and its consultant, PB, spent a considerably longer period of time working with ETSA to understand and assess ETSA's forecast capex than the AER and its consultant, Nuttall Consulting, have spent engaging with CitiPower and Powercor Australia on their respective capex forecasts. The contrast is particularly marked against the background that, for ETSA, the AER was required to assess only 1 capex forecast for 1 distribution business, whereas for CitiPower and Powercor Australia it must assess 2 such forecasts, one for each of the 2 distribution businesses.
- In adopting the costs that would be incurred by the group to which the DNSP belongs as the benchmark or counterfactual against which to assess Victorian DNSPs' expenditure under outsourcing arrangements, the AER departed from the position taken by the AER and the ESCV in the following previous regulatory decisions:
  - the AER's South Australian Draft Determination, wherein the AER considered the costs incurred by ETSA under its commercial contracts with CHED Services for the provision of call centre, FRC and FRC systems support services and noted that it supported the conclusion reached by its own consultant, PB, that *'outsourcing these services results in lower costs than providing the services in-house on a stand alone basis'*[5];
  - the AER's Jemena Gas Access Final Decision, wherein it is apparent that the AER did not assess whether the margin incurred by Jemena Gas under its outsourcing arrangements reflected the amount required by the contractor to recover a reasonable share of its overheads, a return on and of capital invested in physical assets and/or an allowance for asymmetric risks[6]; and
  - the ESCV's GAAR, wherein (in contrast to the AER's assessment framework which, in essence, assumes that any outsourcing arrangement that fails the 'presumption threshold' is inefficient) the ESCV recognised the potential for, and undertook a detailed inquiry to determine whether, outsourcing arrangements that fail the 'presumption threshold' are a more efficient means of delivering a service than in-house provision.

[5] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p206.
[6] AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), pp56-57 and 267-273.

- In the South Australian Final Determination, the AER adopted growth in installed zone substation capacity as one of the three physical metrics used in the composite network growth factor adopted by the AER for scale escalation based on advice from its consultant, PB. However, in the Draft Determination, the AER adopted growth in the number of zone substations in place of growth in installed zone substation capacity as the relevant physical metric used in the composite network growth factor. In so doing, the sole reason advanced by the AER was that this 'was proposed by SP AusNet'.
- In the South Australian Final Determination, the AER accepted ETSA's forecast network insurance in reliance on the Aon report commissioned by ETSA. In so doing, the AER accepted the advice of its expert consultant, PB, to the effect that *'PB was satisfied that ETSA Utilities' forecast network insurance allowances are prudent and efficient'*[7] and itself concluded that the approach taken by Aon in its report was *'transparent and reasonable'* and that the resultant insurance allowances were 'prudent and efficient'.[8] However, in the Draft Determination, the AER rejected CitiPower's proposed insurance step change on the basis that it was not satisfied that CitiPower's future insurance premiums would increase in the manner forecast by Aon in a report for CitiPower. The AER reached this conclusion despite the fact that:
    - the Aon report for CitiPower was substantially similar to that commissioned by ETSA and accepted by the AER and its adviser, PB, as 'transparent and reasonable' in the South Australian Final Determination; and
    - CitiPower's insurance program is undertaken jointly with Powercor Australia and ETSA.
- In determining the materiality threshold to apply to nominated pass through events in its Draft Determination, the AER rejected its approach in the Previous Distribution Determinations for the ACT, NSW, Queensland and South Australia of applying a materiality threshold to specific nominated pass through events of the administrative costs of assessing the application. Rather, the AER determined that all nominated pass through events should have a materiality threshold of one per cent of smoothed forecast revenue in the years of the regulatory control period the costs are incurred.
- In its approach to nominated pass through events in its Draft Determination, the AER revised its view of 'forseeability' since the Previous Distribution Determinations for the ACT, NSW, Queensland and South Australia such that it now considered that 'forseeability' should be viewed in terms of whether the event is capable of being tightly defined in advance, rather than the probability of the event occurring. As a result, the AER rejected a general nominated pass through event. The AER's Draft Determination is

[7] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p220.
[8] AER, South Australia Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p221.

inconsistent with its inclusion of this event in its Previous Distribution Determinations.

- In rejecting CitiPower's proposed S factor true up control mechanism term, the AER stated that it was constrained by clause 6.12.3(c) of the Rules from changing the control mechanism formula set out in the Framework and Approach Paper. However, in the South Australian Draft Determination, the AER determined that this rule only prevents it from changing the form of control (e.g. from a WAPC to a revenue cap) and does not prevent it from adding new terms to the formula. The AER's approach is also inconsistent with its approach in the Queensland Final Determination where it added new terms to the formula that were not included in the Queensland Framework and Approach Paper.
- In rejecting CitiPower's proposal to include a term in the WAPC and side constraint formulae to provide for the recovery of Transmission-related Costs on the basis that it had no power to amend the form of these formulae set out in the Framework and Approach Paper, the AER departed from its approach in Previous Distribution Determinations. For example:
    - in the South Australian and the Queensland Final Determinations, the AER took the view that, while the form of control mechanism (e.g. from a WAPC to a revenue cap) must be as set out in the relevant Framework and Approach Paper, the WAPC and side constraint formulae could be amended to include an additional term (and the AER did, in fact, add new terms to the WAPC formula in those Final Determinations even though no such terms were included in the WAPC formula in the relevant Framework and Approach Paper); and
    - perhaps more significantly, in the South Australian and Queensland Final Determinations, the AER established a mechanism for the calculation of transmission related payments to be passed through by ETSA and the Queensland DNSPs pursuant to their pricing proposals, referred to as the 'TuOS unders and overs account'. While clause 6.18.7 of the Rules only contemplates the pass through of TuOS charges via a DNSP's pricing proposal, the AER nonetheless explicitly provided for the pass through by ETSA and the Queensland DNSPs of certain of the Transmission-related Costs presently in issue, namely avoided TuOS payments and inter-DNSP payments, in the AER's 'TuOS unders and overs account'.[9]

Thus, the AER has previously recognised its power to include additional terms in the WAPC and side constraint formulae not reflected in its relevant Framework and Approach Paper and established a mechanism for recovery of certain of the Transmission-related Costs presently in issue through

[9] AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), Appendix F, Table F.1, p323; AER, Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), Appendix E, Table E.1, p396.

inclusion of an additional term in the WAPC and side-constraint formulae. Yet, in the Draft Determination, the AER resists the establishment of any mechanism for the recovery of CitiPower's Transmission-related Costs despite the fact that CitiPower is statutorily required to incur these Costs in the provision of standard control services and they are, thus, uncontrollable in nature and quantum.

CitiPower maintains that, (at least in part) as a result of these differences of approach, the distribution price movements approved in the AER's Draft Determination are in stark contrast to those approved in the AER's Previous Distribution Determinations. These distribution price movements are set out in Table 1.1 below.

	First year (% price change)	Remaining 4 years (% price change per annum)
Victorian DNSPs (AER's Draft Determination - real)		
CitiPower	-7.27	0 to 2
Powercor Australia	-8.14	0
SP AusNet	-4.46	0 to -6
UED	-19.57	0 to 5
Jemena	-1.46	-2 to -6
Queensland DNSPs (AER's Queensland Final Determination - real)		
Ergon Energy	29.61	5.10
Energex	18.20	7.90
South Australian DNSP (AER's South Australian Final Determination - real)		
ETSA	10.95	3.9
New South Wales DNSPs (AER's NSW Final Determination - real)		
Energy Australia	17.86	12.0 to 8.0
Integral Energy	12.58	7.0 to 0.0
Country Energy	13.41	13.31 to 0

Table 1.1: AER approved distribution price movements in Draft Determination and Previous Distribution Determinations

1.2.1.2 AER attempts to align Final Determinations of Victorian DNSPs

In the Draft Determination, the AER's reasoning and approach to assessing CitiPower's Initial Regulatory Proposal is influenced by the AER's objective of ensuring a consistent outcome in its Final Determinations for the Victorian DNSPs.

As noted above, CitiPower agrees with the AER that a consistent process and approach to assessing distribution regulatory proposals, both as between individual Victorian DNSPs and as between the Victorian DNSPs and DNSPs in other jurisdictions, is important. However, CitiPower is also concerned to ensure that the AER does not fall into error by assessing its Current Regulatory Proposal against those of the other Victorian DNSPs or seeking through its decision making to align its Final Determinations for each of the Victorian DNSPs.

The regulatory proposals made by other Victorian DNSPs and the decision reached by the AER in its assessment of such proposals are of no relevance to the AER's assessment and decision on CitiPower's Initial or Current Regulatory Proposal. The statutory test the AER is required to apply in assessing CitiPower's forecasts of opex and capex under clauses 6.5.6 and 6.5.7 of the Rules, in particular, does not permit the AER to adopt as a decision making criterion the objective of aligning its Final Determinations across the Victorian DNSPs or to have regard to the regulatory proposals made by other Victorian DNSPs. If the AER were intended to have regard to such matters, the mandatory considerations set out in clauses 6.5.6(e) and 6.5.7(e) of the Rules would include the regulatory proposals received by the AER from other DNSPs in the relevant participating jurisdiction. Another Victorian DNSP's failure, in a regulatory proposal, to seek expenditure proposed by, or the same quantum of expenditure as, CitiPower is of little probative value in evidencing that the expenditure sought by CitiPower is required by it to achieve the opex or capex objectives (as the case may be).

However, in the Draft Determination, the AER assesses CitiPower's Initial Regulatory Proposal against those of the other Victorian DNSPs in its application of the statutory test established by clauses 6.5.6 and 6.5.7 of the Rules and otherwise actively seeks to align its Final Determinations for each of the Victorian DNSPs. A notable example is provided by the AER's consideration of the growth drivers proposed by the Victorian DNSPs for the purposes of scale escalation. In particular, the AER:

- observed that the Victorian DNSPs proposed ten different growth drivers (nearly all of which were proposed by one DNSP); [10]
- rejected CitiPower's proposal that undepreciated replacement cost be adopted as the network growth driver for the purposes of scale escalation, in part, because *'only CitiPower and Powercor considered undepreciated replacement cost to be a representative driver of network growth and in-turn opex'*[11] and *'CitiPower and Powercor's proposed growth rates result in scale opex forecasts significantly above the other DNSPs'*[12];

[10] AER, Draft Determination, Appendix J, p89.
[11] AER, Draft Determination, Appendix J, p90.
[12] AER, Draft Determination, Appendix J, p95.

- adopted two growth drivers, one of which was a composite network growth factor based on three physical metrics and the other of which was the annual growth in customer numbers over the 2011-15 period, for all of the Victorian DNSPs;[13] and
- in so doing, adopted growth in the number of zone substations (rather than growth in installed zone substation capacity as it did in the South Australian Final Determination based on advice from its consultant, PB) as one of three physical metrics used in the composite network growth factor for the sole stated reason that this *'was proposed by SP AusNet'*.[14]

1.2.1.3 Failure by AER to apply 'propose and respond' framework

The Rules establish a 'propose and respond' framework for the AER's assessment of a DNSP's forecasts of opex and capex in its regulatory proposal.[15] This framework requires the AER to:

- assess CitiPower's proposal against the opex and capex criteria;
- only if it is not satisfied that that proposal reasonably reflects the criteria, substitute its own forecast, amount or methodology; and
- in so doing, ensure that its own forecast, amount or methodology departs from that proposed only to the extent necessary to enable the AER to be satisfied that the opex and capex criteria are met.

The Tribunal described the application of this propose and respond framework to a DNSP's forecast opex, in *Application by Energy Australia and Others*[16], as follows:

> *'…the role of a DNSP is to provide the AER with an opex forecast that reasonably reflects the three opex criteria and the AER must accept the forecast if it is satisfied that the total of the forecast reasonably reflects the three criteria. Energy Australia is correct to submit that it is not the AER's role to simply make a decision it considers best. It is also correct for it to say that the AER should be very slow to reject a DNSP's proposal backed by detailed, relevant independent expert advice because the AER, on an uninformed basis, takes a different view. Nor, as EA submits, may the AER reject such a proposal merely because it has an expert opinion. The AER, based upon any expert advice, needs to make its own evaluation, an evaluation that is reviewable by this Tribunal.'*

CitiPower is concerned that the AER's approach in the Draft Determination is, in places, inconsistent with this propose and respond framework. In particular,

[13] AER, Draft Determination, Appendix J, p95.
[14] AER, Draft Determination, Appendix J, p95 and footnote 47.
[15] Australian Government Solicitor, Letter of advice to Mr Tom Motherwell, Department of Industry Tourism and Resources titled 'Assessment of expenditure forecasts', 10 October 2006 (Attachment 20 to this Revised Regulatory Proposal).
[16] [2009] ACompT 8 at [190] (Attachment 97 to this Revised Regulatory Proposal).

CitiPower observes that the following elements of the Draft Determination are indicative of substitution by the AER of its preferred forecast, amount or methodology in circumstances where the AER has not first determined that CitiPower's proposal does not reasonably reflect the opex and capex criteria and the minimum adjustment to that proposal necessary to enable the AER to be satisfied that the opex and capex criteria are met:

- Aside from cursory comments that the AER considered its adjustment to CitiPower's forecast capex to be the minimum adjustment necessary, there is no evidence in the Draft Determination of the AER seeking to identify the minimum adjustment to CitiPower's forecast capex necessary. The AER has simply identified and adopted point estimates based on Nuttall Consulting's recommendations, including in reliance on historical expenditure trends and the Repex Model. In order to comply with the Rules, CitiPower submits that the AER must adjust the capex forecasts included in this Revised Regulatory Proposal to the minimum extent necessary to reach satisfaction under the Rules.
- As discussed above, the AER assesses CitiPower's Initial Regulatory Proposal against those of the other Victorian DNSPs in its application of the statutory test established by clauses 6.5.6 and 6.5.7 of the Rules and otherwise actively seeks to align its Final Determinations for each of the Victorian DNSPs. Such an approach is inconsistent with the propose and respond framework established by the Rules, which requires the AER to assess CitiPower's proposal directly against the opex and capex criteria and to amend any forecast, amount or methodology in the proposal only to the extent necessary for it to be satisfied the resultant forecast, amount or methodology reasonably reflects the opex and capex criteria. Any alignment by the AER of its Final Determinations for each of the Victorian DNSPs will necessarily involve either rejection and amendment of CitiPower's proposal in circumstances where that proposal reasonably reflects the opex and capex criteria and/or amendment of that proposal otherwise than to the minimum extent necessary to be satisfied that the resultant forecast, amount or methodology reasonably reflects the opex or capex criteria.
- The AER also, on occasion, rejects a methodology in CitiPower's Initial Regulatory Proposal (at least in part) because CitiPower's methodology results in a different forecast or amount to that preferred by the AER. For example:
    - the AER rejects CitiPower's proposal to use undepreciated network replacement cost as a growth driver for the purposes of scale escalation, in part, because *'CitiPower and Powercor's proposed growth rates exceed the growth rates of substitute drivers'*;[17] and
    - the AER assumed that historical reliability and quality maintained capex was efficient and, accordingly, assessed CitiPower's forecast

[17] AER, Draft Determination, Appendix J, p90.

> reliability and quality maintained capex in greater detail where it exceeded historical capex. If it was not satisfied that the expenditure in excess of historical capex was efficient, the AER adopted a model for forecasting reliability and quality maintained capex that *'was ... calibrated so that it reflected historical levels and costs'*.[18] In short, the AER's forecasting methodology results in a forecast of reliability and quality maintained capex that reflects historical capex and, thus, is consistent with its starting assumption that historical reliability and quality maintained capex is efficient.

Again, this is not consistent with the Rules' propose and respond framework. A divergence in the output of the AER's preferred methodology and that proposed by CitiPower does not suffice to establish that CitiPower's proposed methodology does not reasonably reflect the opex or capex criteria.

1.2.1.4 Adoption of 'revealed cost' approach to forecast capex

In its Draft Determination, the AER largely adopted a 'revealed cost' approach to assessing CitiPower's proposed capex and forecasting substitute capex.[19]

With the exception of customer connections capex (in respect of which CitiPower accepts a revealed cost approach may be appropriate), historical expenditure is not a reasonable basis on which to prepare forecasts of capex for 2011-15 that reasonably reflect the capex criteria.

The AER acknowledged as much in its Draft Determination, saying in respect of environmental, safety and legal capex, SCADA and network control and non-network capex that the *'historic trend cannot completely determine future requirements'*.[20] Similarly, the ESCV recognised in its 2006-10 EDPR that there are reasons why historical capex will not necessarily be indicative of capex going forward, including in particular growth in maximum demand and the ageing of the asset base.[21]

CitiPower notes that both maximum demand and the average asset age of its network is expected to increase in the next regulatory control period (see Chapters 4 and 9 of this Revised Regulatory Proposal). CitiPower also observes that the risks its network will face in the next regulatory control period will not be the same as the risks it faced in the past. Accordingly, CitiPower is concerned that the Draft Determination fails to provide for capex that would be required by an efficient and prudent operator to meet the capex objectives.

[18] AER, Draft Determination, pp338-9.
[19] AER, Draft Determination, p288.
[20] AER, Draft Determination, pp399, 409, 419 and 429.
[21] ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), p269.

1.2.1.5 Imposition of evidentiary threshold requirements

In the Draft Determination, the AER sought to establish evidentiary thresholds, or put another way minimum evidentiary requirements, for the AER's satisfaction that the proposed capex forecasts reasonably reflect the capex criteria. In particular, the AER sought to establish the following evidentiary thresholds:

- formal cost benefit analysis, including options analysis, and/or a risk assessment;
- internal cost benefit analysis (rather than external expert analysis); and
- cost benefit analysis quantifying benefits and/or demonstrating a net benefit in circumstances where a DNSP's forecast capex is required to achieve compliance with its mandatory legal obligations.

CitiPower considers that the establishment of evidentiary threshold is unreasonable and not permissible at law.

CitiPower submits that the AER cannot, at law, seek to establish threshold evidentiary requirements (such as formal cost benefit analysis, including options analysis, and/or a risk assessment) for the AER to be satisfied that a DNSP's forecast capex reasonably reflects the capex criteria. In *Telstra Corporation Limited v Australian Competition Tribunal*, the Full Federal Court agreed with Telstra that the Tribunal had fallen into error by devising a set of rules (which it called a 'road map') that the evidence adduced by Telstra must address in order for the Tribunal to be satisfied as to the statutory test established by section 152AT(4) of the Trade Practices Act, rather than directly applying the statutory test to the evidentiary material before it.[22] The Court concluded that *'[t]o impose a requirement of empirical evidence which addressed the matters set out in the road map as a minimum set of standards ... is, as Telstra submitted, to apply the wrong test'* and was *'an error of law ... fundamental to its decision'*.[23]

In addition, CitiPower submits that it is not open to the AER, acting reasonably, to:

- set evidentiary thresholds for the AER's satisfaction under the Rules at a level that is unduly onerous and demanding, and which ignores the practical constraints on adducing the relevant evidentiary material; and
- conclude that it is not satisfied that a DNSP's forecast capex reasonably reflects the capex criteria because the cost benefit analysis before it was performed by an independent expert rather than the DNSP itself.

Finally, CitiPower submits that, in circumstances where a DNSP's forecast capex is the efficient cost required to achieve compliance with its mandatory legal obligations:

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[22] (2009) 175 FCR 201 at [171]-[175].
[23] (2009) 175 FCR 201 at [174] & [175].

- the AER has no discretion to refuse to allow that capex on the basis that the DNSP has not demonstrated a net benefit associated with that capex or has not quantified the benefits and outcomes for consumers; and
- it is not legally permissible for the AER to require a risk assessment, on the basis that regulators of these obligations have adopted a 'risk based approach' to compliance, as a precondition to AER satisfaction that that capex reasonably reflects the capex criteria.

1.2.1.6 Historical accuracy of DNSPs' forecasts

In its Draft Determination, the AER had regard to the past forecasting performance of Victorian DNSPs.[24] The AER concluded that Victorian DNSPs' capex forecasts tend to systematically over estimate actual capex.[25]

In comparing CitiPower's historical capex to the benchmark set by the ESCV (set out in Table 1.2 below), CitiPower's expenditure is below the ESCV's aggregate benchmark in the years 2006 and 2007. However, the variance almost exclusively relates to reinforcement expenditure, in particular, the deferral of the Metro 2012 project. This was discussed in more detail in CitiPower's Initial Regulatory Proposal.[26] More significantly, actual expenditure in 2006-09, coupled with expected expenditure in 2010, varies from the total benchmark set by the ESCV by a negligible amount.

	$'000s (real 2010)					
Capex	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
Actual	102,306	94,326	115,798	124,706	147,985	585,121
Regulatory allowance	120,186	114,715	113,054	124,105	105,224	577,285
Difference	**(17,881)**	**(20,389)**	**2,744**	**602**	**42,761**	**7,837**

Table 1.2: Comparison of gross capex in 2006-10 to ESCV allowance for 2006-10

1.2.1.7 Windfall gains and drawing of adverse inferences by AER

In rejecting CitiPower's proposed adjustments to the calculation of carry over amounts arising from the 2006-10 period, the AER reasoned that it is not appropriate to revisit the design of the ESCV's ECM and/or to make ex post adjustments to the carry over amounts calculated in accordance with that ECM because any adjustment for windfall losses would require a consideration of windfall gains but, given the information asymmetry between the Victorian DNSPs and the AER, it would be difficult to identify any windfall gains received by Victorian DNSPs.[27]

CitiPower observes, however, that:

[24] AER, Draft Determination, pp291-292, 315, 344-345, 409, 418 & 428.
[25] AER, Draft Determination, pp291-292.
[26] Initial Regulatory Proposal, pp145-46.
[27] AER, Draft Determination, pp593-4.

- there is no evidence that CitiPower received windfall gains as a result of uncontrollable cost reductions in the 2006-10 regulatory control period; and
- it is not reasonable for the AER to infer or assume any such gains on the basis of information asymmetry between the Victorian DNSPs and the AER in circumstances where the NEL:
    - confers on it extensive information gathering powers through the issuance of regulatory information notices[28], which powers have been exercised by the AER on more than one occasion during its decision making process; and
    - establishes significant sanctions for non-compliance or the provision of false or misleading information in purported compliance with such a notice.[29]

In addition, where a DNSP fails to comply with a regulatory information notice, the NEL expressly permits the AER to make an assumption or draw an inference adverse to a DNSP in respect of the matters the information required under the notice would have addressed had the information been provided as required.[30] CitiPower maintains that this reflects a statutory intent that the AER has no power to make an assumption or draw an inference adverse to a DNSP except where the AER has first issued a regulatory information notice seeking information in respect of the relevant matter with which the DNSP has failed to comply.

1.2.1.8 Currency of expenditure forecasting inputs

In its Draft Determination, the AER observed in respect of a number of the Victorian DNSPs' input forecasts (e.g. those for energy consumption, maximum demand, labour rates etc) that the DNSPs' forecasts should be updated to reflect the most recent data. In respect of the forecast of labour rates by BIS Shrapnel, the AER appeared to go so far as to reject BIS Shrapnel's forecasting methodology and substitute labour rate forecasts prepared by its consultant, Access Economics, in part, on the basis that the data used by BIS Shrapnel was not current.[31]

Contrary to the AER's apparent reasoning in its Draft Determination, currency of data is not a reason for rejecting a DNSP's proposed methodology for forecasting input costs and other input parameters.

To address the AER's concerns regarding the currency of CitiPower's labour cost escalators, CitiPower is proposing to engage KPMG to update its labour cost forecasts (relied on by CitiPower in this Revised Regulatory Proposal) closer to the date of the AER's Final Determination, at a date of the AER's choosing. In addition, CitiPower is proposing to engage SKM to update its materials escalators

[28] NEL, Part 3, Division 4.
[29] NEL ss28N, 28R, 59 and 74; *Criminal Code Act 1995* (Cth), ss137.1 and 137.2 and *Crimes Act 1914* (Cth), s4B(3).
[30] NEL, s28Q(2).
[31] AER, Draft Determination Appendices, pp136-37.

(relied on by CitiPower in this Revised Regulatory Proposal) closer to the date of the AER's Final Determination, at a date of the AER's choosing. If the AER does not advise of the date by which it would like the updated forecasts, CitiPower will provide the updated forecasts to the AER by 13 September 2010.

Similarly, if the AER has concerns regarding the currency of any other forecasts in CitiPower's Current Regulatory Proposal at any time in the lead up to making its Final Determination, CitiPower requests that the AER inform it and offer CitiPower an opportunity to provide updated forecasts for use by the AER in its Final Determination.

1.2.1.9 Failure to provide certainty as to recovery of costs

In the Draft Determination, the AER rejected parts of CitiPower's Initial Regulatory Proposal that would have allowed CitiPower to recover costs that it incurs in providing direct control network services and complying with regulatory obligations and requirements. In doing so, the AER did not express any concerns as to whether those costs would be incurred by a prudent operator in CitiPower's circumstances or provide any other valid reasons for declining recovery of those costs.

In particular:

- the AER rejected several of CitiPower's proposed pass through events on the basis that those events could fall within the existing 'regulatory change event' or 'service standard event' definitions.[32] However, the AER did not make a finding that these events would fall within those definitions if they did occur (subject to any materiality threshold). Accordingly, CitiPower has no certainty as to whether it will be able to recover the costs of these events if they do occur;
- the AER rejected CitiPower's proposal that additional terms should be added to the control mechanism formula to allow the recovery of Transmission-related Costs.[33] The AER acknowledged that these Costs would be incurred and that there was no other mechanism for their recovery under the Rules, but failed to include a mechanism for their recovery under the Draft Determination; and
- the AER rejected CitiPower's proposal that any events that are proposed by CitiPower as nominated pass through events but are not accepted by the AER should be included as excluded cost categories for the purposes of the EBSS.[34] The AER considered that these events may already be covered by the 'regulatory change event' or 'service standard event' definitions but, as noted above, the AER did not make a finding that they would be covered by those definitions if they occurred. The AER also stated that it was not necessary to exclude the costs related to these events because some of the

[32] AER, Draft Determination, pp708-710.
[33] AER, Draft Determination, pp 62-66.
[34] AER, Draft Determination, p609.

events related to revenue and not costs and therefore would not affect the EBSS. However, that comment only applied to a small minority of the events proposed by the DNSPs and is not correct for any of the events proposed by CitiPower.

1.2.2 Response to Draft Determination's rejection of CitiPower's Initial Regulatory Proposal

In its Draft Determination, the AER did not accept a number of aspects of CitiPower's Initial Regulatory Proposal. This Revised Regulatory Proposal addresses these specific matters raised by the AER in its Draft Determination.

As discussed in section 1.2.2.1 below, CitiPower accepts, or does not contest, the AER's decisions or conclusions on a number of these specific matters and, accordingly, incorporates those decisions or conclusions into its Current Regulatory Proposal. However, these are also a number of the AER's decisions or conclusions that CitiPower does not accept. Its response to these is summarised in section 1.2.2.2 below.

1.2.2.1 Incorporation in Revised Regulatory Proposal of Draft Determination

In the Revised Regulatory Proposal, CitiPower accepts (or does not contest) a number of the decisions or conclusions of the AER in the Draft Determination to reject aspects of CitiPower's Initial Regulatory Proposal. The decisions or conclusions of the AER in the Draft Determination that CitiPower has accepted, or does not contest, include but are not limited to:

- the AER's classification of services in the Draft Determination with the exception only that CitiPower has decided it will not provide the fault level compliance service given the AER's classification of that service as an alternative control (fee based) service;
- the AER's decision in respect of CitiPower's outsourcing arrangements to:
    - exclude the margin payable by CitiPower under its outsourcing arrangements with CHED Services, PNS and Silk Telecom from the calculation of the efficiency carryover mechanism amounts for the period 2006-09;
    - include the margin payable by CitiPower under those contracts in the 2006-09 actual capex that is used in the RAB roll forward calculation; and
    - exclude the administration fee payable to CHED Services under the DRMS from its expenditure forecasts for the 2011-15 regulatory control period and the calculation of the EBSS carry over amounts for 2011-15;
- the AER's adjustment to base year opex to remove regulatory reset costs;

- the AER's decision to roll forward the 2009 base year opex to 2010 by inflating the 2009 costs by the change in costs assumed by the ESCV, adjusted for the difference between forecast and actual growth, in determining the benchmark opex allowance for 2009 and 2010 in its 2006-10 EDPR;
- the AER's decision regarding the following step changes:
  - the step change proposed by CitiPower in respect of self insurance;
  - the step change proposed by CitiPower in respect of compliance with the Electricity Safety Management Regulations;
  - the step change proposed by CitiPower in respect of the national framework for distribution network planning and expansion;
  - the step change proposed by CitiPower in respect of the customer charter; and
  - to include a step change in respect of regulatory submission costs;
- the approach set out in the Draft Determination in relation to the opening RAB, except for the AER's adjustment to the value of 2005 disposals. CitiPower considers that the AER does not have any power under the Rules to make this adjustment;
- the AER's calculation of depreciation and asset lives set out in the Draft Determination, except that CitiPower considers that a number of amendments are required to the AER's calculations;
- the AER's value for the MRP of 6.5 per cent for the purpose of calculating the cost of capital;
- the AER's decision in Chapter 17 of the Draft Determination on the application of the DMIS to it in the 2011-15 regulatory control period;
- the AER's decision not to nominate pass through events for the wind farm connection costs event and the network extension for remote generation event proposed in CitiPower's Initial Regulatory Proposal; and
- the AER's decision in respect of the calculation of the estimated cost of corporate income tax to modify the statutory corporate income tax rate to take account of the Commonwealth Government's policy announcement that it intends to reduce the company tax rate. However, the AER should update its approach to take into account the Commonwealth Government's most recent announcement that it will now only reduce the company tax rate to 29 per cent and not 28 per cent.

Accordingly, the revisions made by CitiPower to its Initial Regulatory Proposal include the revisions required to incorporate CitiPower's acceptance of the matters detailed above in its Current Regulatory Proposal. CitiPower observes, however, that, while it has incorporated many of the AER's adjustments to its Initial Regulatory Proposal in its Current Regulatory Proposal, this should not be construed as acceptance by CitiPower of the AER's rationale, or the rationale of any of its consultants, for those adjustments. In addition, CitiPower observes that it accepts the above matters for the purposes of its Current Regulatory Proposal and the current distribution price review only.

1.2.2.2 Departures in Revised Regulatory Proposal from Draft Determination

CitiPower does not accept in the Revised Regulatory Proposal a number of the decisions or conclusions of the AER in the Draft Determination to reject aspects of CitiPower's Initial Regulatory Proposal. These include but are not limited to:

- the AER's decision not to include any mechanism, including in particular any term in the control mechanism formulae, to allow the recovery of Transmission-related Costs;
- the AER's decision not to include an S factor true up correction factor in the control mechanism formulae;
- the AER's decision to substitute its own forecasts of energy consumption and maximum demand for the 2011-15 regulatory control period;
- the AER's decision to exclude the margin payable under its Corporate Services Agreement with CHED Services, its Network Services Agreement with PNS and its Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom from its opex and capex forecasts for the 2011-15 regulatory control period and the calculation of the EBSS carry over amounts for 2011-15;
- the AER's adjustments to base year opex:
    - to account for movement in the provisions relating to employee entitlements;
    - to exclude related party margins payable in 2009 under its Corporate Services Agreement with CHED Services, its Network Services Agreement with PNS and its Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom;
    - in respect of CitiPower's distribution licence fee;
    - in respect of GSL payments;
    - in respect of superannuation payments; and
    - in respect of capitalisation;
- the AER's decision in respect of CitiPower's debt raising costs;
- the AER's decision regarding the following step changes proposed by CitiPower:
    - the step change in respect of insurance;
    - the step change in respect of compliance with the 2010 Line Clearance Regulations;

  - the step change in respect of the WMTS demand management program; and
  - the step change in respect of communications in extreme supply events;
- the growth drivers selected by the AER for the purposes of scale escalation, including in particular the AER's use of growth in the number of zone substations, its adjustments to CitiPower's proposed economies of scale adjustments and the AER's proposed adjustment for the capex/opex trade-off;
- the AER's forecasts of labour cost escalators, its decision to rely on the labour cost growth forecasts prepared by Access Economics in determining those escalators and its decision in respect of CitiPower's proposed materials escalators;
- the AER's decision in respect of CitiPower's total capex forecasts, except in relation to non-network capex;
- the AER's decision on the method for determining the DRP for the purpose of calculating the cost of capital;
- the AER's decision in respect of the calculation of the estimated cost of corporate income tax for the 2011-15 regulatory control period to adopt a value of 0.65 for gamma for the purposes of calculating the cost of capital and the estimated cost of corporate income tax;
- the AER's decision in respect of the calculation of the carry over amounts arising in the 2006-10 period:
  - on adjustments to the carry over amounts arising in the 2006-10 regulatory period; and
  - to reject CitiPower's proposed NPV approach to calculating its 2006-10 carry over amounts;
- the AER's decision to reject CitiPower's proposal that any events that are proposed by CitiPower as nominated pass through events but not accepted by the AER should be excluded cost categories for the purposes of the EBSS;
- the AER's decision to not to nominate the following pass through events proposed by CitiPower:
  - a general pass through event;
  - a financial failure of a retailer event;
- the AER's failure to confirm that pass through events which it rejected on the basis that they could fall within the scope of the 'regulatory change event' or 'service standard event' pass through in the Rules do fall within the scope of those events;

- the AER's decision to set the materiality threshold for nominated pass through events at one per cent of smoothed forecast revenue in the years of the regulatory control period that the costs are incurred; and
- the AER's decision in respect of CitiPower's proposed charges for alternative control services (including public lighting).

In this Revised Regulatory Proposal, CitiPower responds to these decisions or conclusions by either:

- affirming its proposal in the Initial Regulatory Proposal and adducing additional supporting information, documents and material to substantiate that proposal; or
- making revisions to its Initial Regulatory Proposal to address those AER decisions or conclusions, or the AER's reasons for them.

CitiPower's response to those decisions or conclusions in the Draft Determination that it does not accept, together with its Current Regulatory Proposal, are summarised briefly below. However, this Chapter 1 should be read in conjunction with the detailed response to the AER's Draft Determination contained in the other Chapters of this Revised Regulatory Proposal and the supporting Appendices.

The revisions contained within this Revised Regulatory Proposal have been developed following consideration of the issues raised by the AER's Draft Determination, advice from CitiPower's external advisers and additional analysis performed by CitiPower.

Recovery of Transmission-related Costs and S factor true up

CitiPower does not accept the AER's decision in the Draft Determination not to include any mechanism to allow the recovery of Transmission-related Costs.

CitiPower maintains its position in the Initial Regulatory Proposal that the AER should include a new term in each of the WAPC formula and the side constraint formula to address Transmission-related Costs (TRC_t). CitiPower considers that:

- the AER has the power to provide for the recovery of Transmission-related Costs in its distribution determination - clause 6.18.7 of the Rules only prevents the recovery of Transmission-related Costs through a DNSP's pricing proposal but does not prevent the AER from providing for the recovery of those Costs in its Final Determination; and
- the AER has the power to add a term to the WAPC formula - as recognised by the AER in the South Australian Draft Determination, clause 6.12.3(c) of the Rules only prevents the AER from changing the form of control (e.g. from a WAPC to a revenue cap) but does not prevent the AER from adding a term to the WAPC formula.

However, CitiPower also revises its Initial Regulatory Proposal to propose that, if the AER rejects CitiPower's proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs, the AER must:

- increase CitiPower's forecast opex to include the estimated amounts of the Transmission-related Costs for 2011-15 set out in Chapter 3 of this Revised Regulatory Proposal; and
- accept a 'transmission related costs event' as an additional nominated pass through event covering the difference between forecast and actual expenditure in respect of Transmission-related Costs, with a materiality threshold of zero.

CitiPower considers that the AER is required by clause 6.5.6(c) of the Rules to accept this forecast opex, if the AER rejects CitiPower's proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs, because:

- these Costs are incurred in providing direct control network services and complying with regulatory obligations and requirements; and
- accordingly, these Costs are efficient and prudent expenditure required to achieve the opex objectives under clause 6.5.6(a) of the Rules.

CitiPower also maintains that an S factor true up term (T_t) should be added to the control mechanism. The AER rejected CitiPower's proposal to add an S factor true up term to the control mechanism because it considered it had no power under the Rules to do so. As noted above, CitiPower does not agree that the AER has no power to add a term to the WAPC formula. CitiPower also does not agree with the AER's proposed method for calculating the S factor true up amount.

In addition, CitiPower maintains that an analogous true up term (KAY_t) should be added to the control mechanism to provide for a true up of Transmission-related Costs incurred by CitiPower in 2010.

Growth forecasts

CitiPower does not accept the AER's forecasts of energy consumption and maximum demand, substituted for those in CitiPower's Initial Regulatory Proposal on the recommendation of the AER's consultant, ACIL Tasman.

In this Revised Regulatory Proposal, CitiPower adopts revised energy consumption forecasts prepared by NIEIR that reflect updated forecasts of economic growth and population growth consistent with the population growth forecast the AER recommended be used.

However, CitiPower rejects the AER's conclusions based on the advice of ACIL Tasman regarding the policy adjustments to energy consumption forecasts required to ensure that recent or upcoming technological or policy changes that are not reflected in historical relationships are reflected in the forecasts. CitiPower explains the updates to NIEIR's policy adjustments that have occurred to reflect recent policy developments, responds to the AER's and ACIL Tasman's issues and concerns and adduces a further expert report by Frontier that supports the policy adjustments made by NIEIR in updating its energy consumption forecasts.

CitiPower responds to the AER's concerns regarding its maximum demand forecasts in its Initial Regulatory Proposal by:

- explaining why, contrary to the AER's analysis, CitiPower's internal forecasts have been demonstrated historically to have a high degree of accuracy;
- updating its own internal spatial maximum demand forecasts to reflect lower than expected maximum demand in 2009-10 in four zone substations;
- providing revised NIEIR forecasts of maximum demand that are updated for currency and correct for errors made in NIEIR's original maximum demand forecasts provided with CitiPower's Initial Regulatory Proposal;
- reconciling CitiPower's internal spatial maximum demand forecasts with these revised NIEIR forecasts of system maximum demand; and
- following this reconciliation, adopting CitiPower's internal spatial maximum demand forecasts without adjustment in CitiPower's Current Regulatory Proposal, as these forecasts are consistent with NIEIR's revised forecasts of system level maximum demand.

CitiPower has addressed the concerns raised by the AER regarding its customer number forecasts in respect of economic and population growth by adopting updated NIEIR customer number forecasts that reflect updated forecasts of economic growth and population growth consistent with the population growth forecast that ACIL Tasman and the AER recommended be used.

Outsourcing arrangements

CitiPower maintains that the AER should accept the forecasts of total opex and capex included in this Revised Regulatory Proposal without making any adjustment to reduce the expenditure payable by CitiPower to CHED Services under the Corporate Services Agreement, PNS under the Network Services Agreement and Silk Telecom under the Electrical Network Communications Agreement and Corporate Communications Agreement to exclude margins.

In this Revised Regulatory Proposal, CitiPower demonstrates that its forecast expenditure inclusive of margins payable to CHED Services under the Corporate Services Agreement, PNS under the Network Services Agreement and Silk Telecom under the Electrical Network Communications Agreement and Corporate Communications Agreement are prudent and efficient and, thus, consistent with the opex and capex criteria, correctly construed and applied.

In particular, CitiPower maintains that the AER must accept its forecast opex inclusive of any expenditure incurred under the Corporate Services Agreement with CHED Services, the Network Services Agreement with PNS and the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, including the implied margins, without adjustment because:

- the opex criteria, properly construed, do not permit the AER to reduce a DNSP's total expenditure forecasts, for example to exclude margins under outsourcing arrangements, below the efficient costs of achieving the opex objectives; and
- benchmarking analysis conducted by NERA establishes that CitiPower's forecast opex for 2011-15 set out in its Initial Regulatory Proposal inclusive of any expenditure under the Corporate Services Agreement with CHED Services, the Network Services Agreement with PNS and the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, including implied margins, is efficient.

In addition, CitiPower maintains that the AER must accept its forecast expenditure under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, including the implied margins, without adjustment because:

- Contrary to the AER's conclusion, the decision by CitiPower and Powercor Australia to adopt their current service model, under which they pay a margin to CHED Services and PNS, was prudent at the time of that decision and remains prudent if assessed with the benefit of hindsight.
- The expenditure incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS inclusive of margins is prudent and efficient because:
    - the NEL and the Rules, properly construed and applied, require the AER to adopt the stand-alone, in-house cost of service provision (and do not permit the AER to adopt the costs that would be incurred by the group to which the DNSP belongs) as the benchmark or counterfactual for assessing forecast opex and capex under outsourcing arrangements that fail the 'presumption threshold'; and
    - the expenditure incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS inclusive of margins is lower than the stand-alone, in-house cost of service provision.
- Even if (contrary to CitiPower's contentions) the AER maintains its view that the Rules permit it to consider the costs that would be incurred by the group rather than the individual DNSP, CitiPower would nonetheless maintain that the margins payable under the Corporate Services Agreement and the Network Services Agreement should be included, at least in part, in its expenditure forecasts for 2011-15 because:
    - the AER cannot, acting reasonably, take into account efficiencies accruing to a contractor from the provision of services to third parties in circumstances where the AER must exclude the costs associated with the provision of unregulated services from allowed opex and capex; and

    - PNS derived a significant portion of its revenue in 2009 from the supply of services to third parties.

- The margins payable under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS reflect the margins that would be expected to be agreed to by parties operating on an arm's length basis because:
    - contrary to the AER's conclusion, Ernst & Young's analysis of the profit on direct and indirect costs earned by companies providing comparable services to third parties is just as relevant in an economic regulatory context as in a taxation context; and
    - the benchmark margins calculated by Ernst & Young in this manner were adopted as the margins payable under the Corporate Services Agreement and the Network Services Agreement.

Adjustments to base year opex

The AER's adjustments to CitiPower's base year opex in respect of superannuation payments and capitalisation, and to account for movement in the provisions relating to employee entitlements, were incorrect. Accordingly, CitiPower has proposed in this Revised Regulatory Proposal correct adjustments to account for movement in provisions relating to employee entitlements and in respect of capitalisation. CitiPower has retained within its base year opex all superannuation costs, however, has applied a step change for the years 2011-15 based on an actuarial assessment of its defined benefit scheme and the increase in contributions through the accumulation fund to offset retiring employees.

CitiPower does not accept the AER's decision not to apply a customer growth factor to its allowance in respect of GSL payments and accordingly has included in this Revised Regulatory Proposal an allowance based on its average GSL payments over 2005-09 escalated with the customer growth factor set out in Chapter 7 of this Revised Regulatory Proposal.

Debt raising costs

CitiPower does not accept the AER's decision in Appendix P of the Draft Determination in respect of debt raising costs. CitiPower considers that the appropriate allowance for debt raising costs is a total of 24.6 basis point per annum. This allowance is made up of direct debt raising costs of 9.1 basis points and early refinancing costs of 15.5 basis points. This allowance needs to be updated in the Final Determination to use the agreed averaging period.

Step changes

CitiPower does not accept the AER's decision in respect of its proposed step change for compliance with the 2010 Line Clearance Regulations. In response, CitiPower:

- submits that the 2010 Line Clearance Regulations will significantly increase its costs of implementing and maintaining line clearances;
- asserts that the AER cannot rely on the cost impact analysis in the Line Clearance RIS to determine the step change costs of complying with the

2010 Line Clearance Regulations. This is because the Line Clearance RIS failed both to correctly identify the key changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations and to correctly cost compliance with the 2010 Line Clearance Regulations as compared with the 2005 Line Clearance Regulations; and

- sets out its step change costs resulting from the changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations.

CitiPower does not accept the AER's decision to reject its proposed step change in respect of demand management at the WMTS. It is irresponsible for the AER to not provide any opex for the WMTS in circumstances where both the AER and its consultant, Nuttall Consulting, acknowledge that there is an emerging network constraint and that a response will be required to avoid the loss of supply and minimise the load at risk. While the 2009 TCPR identified four options for managing contingent risks at WMTS,[35] the demand management option selected by CitiPower is the only prudent and efficient option.

In respect of its insurance step change, CitiPower proposes to provide the AER with invoices for its actual premiums once they become available in September 2010. CitiPower will accept a step change that reflects the difference between its 2009 and 2010 external insurance. However, for the purposes of this Revised Regulatory Proposal, CitiPower has used a placeholder assumption based on a 15 per cent increase in the premium reported in the 2009 Regulatory Accounts.

The AER failed to comment on CitiPower's proposed step change for communications in extreme supply events. The amendments to the Distribution Code which take effect from 1 April 2010 in respect of communications in extreme supply events will result in increased costs for CitiPower which are not reflected in its base year opex. It is necessary for the AER to allow this step change for CitiPower because the costs associated with the step change satisfy the opex criteria, as the AER has recognised in allowing a similar step change for Jemena and UED.

In this Revised Regulatory Proposal, CitiPower proposes additional step changes in respect of the following matters which have arisen since its Initial Regulatory Proposal and/or arise out of the AER's Draft Determination:

- the Commonwealth Government's announcement in respect of the superannuation guarantee levy;
- compliance with the AER's outcomes monitoring framework that is foreshadowed in Chapter 21 of its Draft Determination; and
- compliance with the AER's proposed tariff assignment requirements in Annexure G of its Draft Determination (unless the AER accepts CitiPower's proposal in Chapter 3 of this Revised Regulatory Proposal to amend those requirements).

[35] Victorian DNSPs, Transmission Connection Planning Report Produced jointly by the Victorian Electricity Distribution Businesses, 2009, extract on West Melbourne Termination Station 66kV (Attachment 251 to this Revised Regulatory Proposal).

Scale escalation

While CitiPower accepts the AER's use of a composite growth factor based on physical metrics as a network growth driver, CitiPower contends that the growth in the number of zone substations is not a reasonable indicator of the growth in operating and maintenance activity levels resulting from network growth. Rather, CitiPower considers that a network growth escalator based on the simple average of growth in line length, transformers and installed zone substation capacity is appropriate.

CitiPower does not contest the AER's decision to reject its work volume escalator and has applied a network growth escalator to the relevant capex categories instead.

Noting the AER's acceptance of its customer growth escalator in the Draft Determination, CitiPower includes in this Revised Regulatory Proposal an updated customer growth escalator, which reflects current customer growth forecasts based on more recent macro economic data.

CitiPower accepts the AER's rejection of the escalation of the 'Emergency faults (meters)', 'Meters, timeswitches & services maintenance', 'Metering communications' and 'New connections' opex categories (function codes 311, 430, 435 and 852). CitiPower has also adopted the AER's economies of scale adjustment of 50 per cent for the 'Quality audits' opex category (function code 482). However, CitiPower maintains that its remaining economies of scale adjustments, and its application of these adjustments, are reasonable.

CitiPower submits that the AER should not make a downward adjustment to its opex due to the reliability and quality maintained capex proposed in its Revised Regulatory Proposal. CitiPower considers that the approach adopted by the AER to determining the capex/opex trade-off is unreasonable and results in a significant understatement of the opex that CitiPower, acting efficiently and prudently, will require in the next regulatory control period. In particular, the AER's approach fails to take into account the increasing average asset age of CitiPower's network, which implies that CitiPower's opex should be expected to increase (rather than decrease) in the next regulatory control period. Acting conservatively, however, CitiPower has not included any amounts in this Revised Regulatory Proposal to reflect the increase in opex it anticipates will arise in the next regulatory control period given its proposed level of capex.

Real cost escalators

CitiPower does not accept the AER's forecasts of labour costs. In particular, CitiPower maintains that labour cost escalators based on the AWE measure and not the LPI measure (as used by the AER's consultant, Access Economics) will produce opex and capex forecasts that reflect a realistic expectation of cost inputs in the next regulatory control period. In the Revised Regulatory Proposal, CitiPower uses forecasts prepared by KPMG which are based on AWE measures of wage growth and take account of projected productivity increases. Contrary to the approach taken by the AER to determining labour escalators for internal labour, CitiPower maintains that it is appropriate to apply the labour rate forecasts for the EGW industry to both specialist EGW employees and clerical and administrative staff.

In addition, in this Revised Regulatory Proposal, CitiPower uses updated materials escalators determined by independent engineering consultant, SKM.

As noted above, to address the AER's concerns regarding the currency of labour and material cost forecasts, CitiPower will update its labour and material cost forecasts closer to the date of the AER's Final Determination, at a date of the AER's choosing or, if no date is nominated by the AER, then CitiPower will provide the updated forecasts to the AER by 13 September 2010.

Capex overview

CitiPower does not accept the AER's rejection of its proposed capex forecasts for the next regulatory control period. CitiPower submits that the AER's downward adjustment of just over $490 million over the next regulatory control period results in a capex allowance that does not reasonably reflect the capex criteria and does not constitute the minimum adjustment to CitiPower's proposed capex allowance necessary for the resultant allowance to reasonably reflect the capex criteria.

Customer connections capex

CitiPower has amended its customer connections capex forecasts in this Revised Regulatory Proposal to:

- respond to the AER's concerns with its calculation of gross customer connections capex; and
- reflect the AER's recent decision regarding CitiPower's upstream augmentation charge rates.

However, CitiPower contends that the AER has made an error in removing function codes 114 and 115 from standard control and allocating them to alternative control.

CitiPower does not accept the AER's rejection of all proposed expenditure under function code 118. CitiPower expects to receive a number of requests for embedded generation in the next regulatory control period and, accordingly, has included an amount against this function code to allow for this.

Reinforcement capex

CitiPower submits that its methodology for forecasting reinforcement capex does not result in a systematic upward bias in the estimate of future prudent and efficient reinforcement capex. This is because:

- CitiPower's internal planning criteria incorporate the same criteria as CitiPower's governance documents, which Nuttall Consulting concluded would be expected to deliver prudent and efficient outcomes;
- CitiPower's processes take into account synergies and result in forecasts that are economically justified;
- overall, SKM found that CitiPower's energy at risk modelling (including its load duration and transformer outage rate assumptions) is likely to understate energy at risk; and
- the zone substation level maximum demand forecasts used to prepare the reinforcement capex forecasts are consistent with NIEIR's system maximum demand forecast and thus the maximum demand forecasts used for the purposes of forecasting reinforcement capex are not likely to result in a systematic upward bias in the estimate.

CitiPower rejects Nuttall Consulting's approach to forecasting reinforcement capex in the next regulatory control period.

CitiPower contends that each of the reinforcement projects in the Revised Regulatory Proposal will be required as proposed in the next regulatory control period. CitiPower also maintains that the additional expenditure associated with the Metro 2012 and CBD Security of Supply Projects are prudent and efficient.

Reliability and quality maintained capex

CitiPower maintains that its reliability and quality maintained capex forecasts reasonably reflect the capex criteria. CitiPower has provided in this Revised Regulatory Proposal additional details regarding key reliability and quality maintained capex programs for the next regulatory control period.

CitiPower does not consider that the Repex Model is capable of forecasting reliability and quality maintained capex that reasonably reflects the capex criteria. However, even if the calibrated Repex Model is assumed to produce reasonable forecasts, the independent expert, PB, found that the Repex Model supports CitiPower's forecasts. Removing the two major drivers of the increase in CitiPower's forecast in the next regulatory control period (the fault level mitigation and reliability replacement programs), which PB considered should be evaluated as step change increases, PB concluded that the variation between the calibrated Repex Model and CitiPower's forecasts did not justify an adjustment to CitiPower's proposed forecast.

Environmental, safety and legal capex

CitiPower does not contest the AER's Draft Determination with respect to environmental, safety and legal capex. However, CitiPower contends that the AER should include 2009 actual data in its trend analysis and in forecasting the capex required in the next regulatory proposal by reference to historical expenditure.

SCADA and network control capex

The AER has not considered the circumstances of CitiPower network in assessing its proposed SCADA and network control capex. CitiPower contends that its SCADA and network control programs in the next regulatory control period are required and provides in this Revised Regulatory Proposal additional information regarding key programs.

Non-network capex

CitiPower maintains that its proposed non-network – IT capex forecasts reasonably reflect the capex criteria.

CitiPower's expenditure in the current regulatory control period has been reduced relative to the ESCV's allowance in its 2006-10 EDPR as a result of the mandated AMI roll-out. CitiPower does not consider that an event such as the AMI roll-out will occur in the next regulatory control period that would constrain CitiPower's non-network – IT capex to the level of its actual expenditure in the current regulatory control period. CitiPower rejects Nuttall Consulting's assertion that its IT systems are not 'agile' and submits that its proposed expenditure is required to ensure that its systems will remain 'agile' in the next regulatory control period.

The AER cannot discount the evidentiary value of the external cost benefit analysis CitiPower obtained from PwC in respect of its AMI leveraged project on the basis that it is not an internal assessment. As part of this Revised Regulatory Proposal, CitiPower has removed the one component from the AMI leveraged project that is able to be recovered through the S factor scheme. Even with this adjustment, PwC's review indicates that the AMI leveraged projects give rise to a significant expected net benefit. CitiPower rejects the AER's proposition that reinforcement capex deferrals would contribute to the funding of AMI leveraged projects.

CitiPower does not contest the AER's Draft Determination with respect to non-network – other capex.

Method for determination of DRP for purposes of calculating the cost of capital

CitiPower does not accept the AER's decision on the method for calculating the DRP. In particular, CitiPower considers that:

- the AER's method for determining whether Bloomberg or CBASpectrum (or the average of them) should be used in calculating the DRP is unreliable and does not result in the selection of the service that produces the most accurate estimate of the DRP; and
- the AER's method for extrapolating the Bloomberg fair value curve does not result in an accurate measure of the 10 year corporate bond rate.

Accordingly, the method for determining the DRP proposed by CitiPower in its Current Regulatory Proposal is as follows.

- The DRP should be determined based on the CBASpectrum or Bloomberg fair value curves, or an average of CBASpectrum and Bloomberg.
- The decision whether to base the DRP on the CBASpectrum or Bloomberg fair value curves (or an average of them) should be made in accordance with CitiPower's proposed method set out in Chapter 12 of this Revised Regulatory Proposal and an expert report from PwC.[36]
- Extrapolation of the Bloomberg curve should be performed by using the Bloomberg BBB fair value curve to 6 years and then extrapolating it using the Bloomberg AAA curve to 10 years, in accordance with an expert report from PwC.[37] If the Bloomberg AAA curve is not published during the agreed averaging period, then the AER should use the average of the Bloomberg AAA curve over the latest period for which it was available.
- If the CBASpectrum curve (or the average) is considered to be the appropriate curve to use, then only the 5 year measurement from the CBASpectrum curve should be used and to that 5 year observation should be added an amount equal to the change in the Bloomberg AAA fair value curve between a 5 and 10 year term.
- Based on CitiPower's proposed method and a measurement period of the 30 business days from 19 April to 31 May 2010, CitiPower considers that the appropriate indicative DRP is 4.28 per cent. Prior to the Final Determination, this indicative value will be replaced with data from the agreed averaging period.
- If the AER does not accept CitiPower's proposed approach for determining the DRP, then the decision whether to base the DRP on the CBASpectrum or Bloomberg fair value curves (or an average of them) should be made in accordance with the modifications to the AER's approach that are set out in the CEG report[38].

Calculation of estimated cost of corporate income tax

CitiPower does not accept the AER's decision, in calculating the estimated cost of corporate income tax for the 2011-15 regulatory control period, to adopt a value for gamma of 0.65.

CitiPower maintains that, in light of the underlying criteria, a material change in circumstances since the date of the SoRI or another relevant factor make the value for gamma set out in the SoRI inappropriate. CitiPower considers that the

[36] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).
[37] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).
[38] CEG, Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates, A report for Victorian Electricity DBs, July 2010 (Attachment 176 to this Revised Regulatory Proposal).

appropriate value for gamma is 0.5 and proposes this gamma value in its Current Regulatory Proposal.

Calculation of 2006-10 carry over amounts

CitiPower does not accept the AER's decision to:

- reject the adjustments to the 2006-10 carry over amounts proposed by CitiPower to exclude costs not reflected in the ESCV's opex benchmark (superannuation costs and GSL payments) and remove the ESCV's 0.39 per cent partial productivity factor adjustment; and
- reject CitiPower's proposed NPV approach to calculating its 2006-10 carry over amounts.

CitiPower does not accept the AER's decision to reject its proposed adjustments to the 2006-10 carry over amounts proposed by CitiPower to exclude costs not reflected in the ESCV's opex benchmark (superannuation costs and GSL payments) and to remove the ESCV's 0.39 per cent partial productivity factor adjustment. In particular, CitiPower considers that these adjustments are required by the ESCV's approach in the EDPR to calculation of carry over amounts arising from 2001-05, which adopted a principle of requiring adjustments so that there can be a 'like for like comparison' between the ex post opex benchmarks and actual opex. CitiPower does not agree with the AER's reasons for rejecting its proposed adjustments and contends that:

- neither the ESCV's 2006-10 EDPR, the AER's EBSS Guideline nor the NEVA require the AER to apply the ESCV's ECM without making these adjustments; and
- CitiPower had legitimate expectations during the 2006-10 period and at the time of incurring the relevant expenditure that 'like for like' adjustments of the kind proposed would be made and, thus, it is appropriate to make these ex post adjustments.

CitiPower accepts the AER's proposed adjustments to the 2006-10 carry over amounts in relation to AMI reclassification and related party margins. CitiPower does not accept the quantum of the AER's proposed adjustments in relation to licence fees, network growth, non-recurrent expenditure or provisions, although it does accept that adjustments should be made in relation to those matters.

CitiPower revises its Initial Regulatory Proposal to incorporate adjustments for AMI reclassification, related party margins, licence fees, network growth and provisions. Its Revised Regulatory Proposal does not otherwise vary the proposed adjustments to the 2006-10 carry over amounts proposed its Initial Regulatory Proposal.

CitiPower maintains that the AER should apply the ESCV's NPV approach in determining its carry over amounts arising from the 2006-10 period.

Proposed EBSS excluded cost categories

CitiPower does not accept the AER's rejection of its proposal that any costs related to events proposed by CitiPower as nominated pass through events that are not accepted by the AER as nominated pass through events should be treated as uncontrollable for the purposes of the EBSS.

The AER rejected this proposal (despite not accepting these events as nominated pass through events) because it considered that all of these events either:

- are already within the scope of the 'regulatory change event' or 'service standard event' specified in Chapter 10 of the Rules and, thus, automatically excluded from the EBSS calculations; or
- affect revenues and not costs and, therefore, would not affect the EBSS calculation.

CitiPower maintains its proposal that the events proposed by CitiPower as nominated pass through events that are not accepted by the AER as nominated pass through events should be treated as uncontrollable for the purposes of the EBSS because:

- as discussed further in relation to pass throughs below, the Draft Determination provides no certainty that, if these events arise, they will be treated by the AER as regulatory change events or service standards events if and when they arise;
- the AER recognises that these events are uncontrollable, in stating that these events are likely to be pass through events specified in Chapter 10 of the Rules, and the events meet all of the requirements under the AER's EBSS Guideline to be an excluded cost category; and
- all of the events proposed by CitiPower as nominated pass through events relate to costs and not revenue and will impact the EBSS if they occur.

Pass through

CitiPower submits that the AER has acted unreasonably in setting a materiality threshold for nominated pass through events of one per cent of smoothed revenue in the years of the regulatory control period that the costs are incurred. The imposition of the threshold results in a fundamental reassignment of risk between DNSPs and customers, which increased risk the DNSPs would have to be compensated for through regulated revenues.

In this Revised Regulatory Proposal, CitiPower asserts that

- consistent with defined pass through events under the ESCV's 2006-10 EDPR, the materiality threshold for nominated pass through events (except for the financial failure of a retailer and the transmission related costs pass through events) should be that the event has a 'material financial impact on the distribution business', with 'material' being interpreted according to its ordinary meaning. CitiPower considers that having regard to its annual revenue profile this would result in a materiality threshold for it of $250,000 over the regulatory control period for each nominated pass through event; and

- there should be no materiality threshold for the financial failure of a retailer pass through event and the 'transmission related costs' pass through event.

Consistent with its Initial Regulatory Proposal, CitiPower asserts that the AER should include as nominated pass through events: recommendations arising from the Bushfires Royal Commission; a general pass through event; and a financial failure of a retailer pass through event. Further, CitiPower considers that the AER should include as a nominated pass through event: conditions or limitations imposed by ESV on provisional acceptance of an ESMS under the Electricity Safety Act. In addition, if the AER rejects its proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs, the AER must include a nominated pass through event in its Final Determination in respect of these costs.

In respect of pass through events which the AER rejected on the basis that they could fall within the scope of the 'regulatory change event' or 'service standard event' pass through in the Rules, the AER should either confirm that those events do fall within that scope (subject to any assessment of whether the quantum of costs is material/immaterial) or treat those events as nominated pass through events.

CitiPower observes that the AER has fallen into error in accepting a submission by UED that the 'regulatory change event' pass through event in the Rules is confined to changes in existing regulatory obligations. Rather, a 'regulatory change event' encompasses any change in regulatory obligations during the regulatory control period, including the removal of an existing regulatory obligation, a change in an existing regulatory obligation and the imposition of a new regulatory obligation.

Alternative control services (including public lighting)

CitiPower does not accept the AER's Draft Determination in respect of alternative control services (including public lighting).

In respect of fee based alternative control services, CitiPower submits that the AER should determine its prices for fee based and quote based alternative control services on the basis that CitiPower should be permitted to recover its efficient costs of providing alternative control services. CitiPower is not able to recover those costs on the basis of its existing charges or the charges proposed in the AER's Draft Determination as is demonstrated through its historical regulatory accounts.

CitiPower disputes certain criticisms by the AER and Impaq of its alternative control services model. Accordingly, in this Revised Regulatory Proposal it has proposed charges for fee based alternative control services based on revisions to the alternative control services model used by the AER for the purposes of its Draft Determination.

CitiPower does not accept the labour rate which the AER has determined in respect of quoted alternative control services. In determining the labour rate, the

AER relied on a report of Impaq. The AER cannot rely on that report for the reasons set out in this Revised Regulatory Proposal. CitiPower's Current Regulatory Proposal includes a labour rate which it submits the AER should approve in respect of quoted alternative control services.

In respect of public lighting, the AER should revise its Draft Determination to:

- apply the general materials escalator which the AER applied to alternative control services to materials other than poles and brackets;
- accept the costs for poles and brackets, patrol vehicles, luminaires and traffic management set out in this Revised Regulatory Proposal; and
- apply the failure rate for T5 (2x14W) lights set out in this Revised Regulatory Proposal.

1.3 Compliance

This Revised Regulatory Proposal is fully compliant with the requirements of the Rules, including references within the Rules to other subsidiary instruments.

As required by the Rules and the Further RIN, CitiPower has identified the key assumptions that underlie the capex and opex forecasts set out in this Revised Regulatory Proposal and two Directors of CitiPower have certified the reasonableness of these key assumptions in the form prescribed in Appendix B to the Further RIN. The key assumptions and the certification of their reasonableness are set out in Appendix 1.1 and Appendix 1.2 to the Revised Regulatory Proposal respectively.

In addition, as required by the Further RIN, CitiPower's Chief Executive Officer, Shane Breheny, has provided a statutory declaration in the form prescribed in Appendix C to that Further RIN. This statutory declaration is set out in Appendix 1.3 to the Revised Regulatory Proposal.

1.4 Structure and approach

For the assistance of the AER, this Revised Regulatory Proposal is structured to mirror the chapters of the AER's Draft Determination. That is, this Revised Regulatory Proposal adopts the chapter headings and numbering used in the Draft Determination subject to the following exceptions:

- there is no 'Arrangements for negotiation' chapter in this Revised Regulatory Proposal because the AER approved the negotiating framework proposed by CitiPower in its Initial Regulatory Proposal;[39]
- there is no 'Demand management incentive scheme' chapter in this Revised Regulatory Proposal as CitiPower accepts the AER's decision in Chapter 17 of the Draft Determination on the application of the DMIS to it in the 2011-15 regulatory control period;

[39] AER, Draft Determination, p47.

- there is no 'Outcomes monitoring and compliance' chapter as CitiPower addresses the AER's proposed outcomes monitoring framework and reporting requirements (to the extent that it is necessary to do so in this Revised Regulatory Proposal) in section 6.5.15 of Chapter 6, 'Operating and maintenance expenditure';
- CitiPower addresses both Chapter 19 and Chapter 20 of the AER's Draft Determination in a single chapter addressing the AER's decisions on alternative control services; and
- CitiPower includes discrete chapters in this Revised Regulatory Proposal on each of scale escalation and real cost escalators (whereas the AER addressed these matters in Appendices J and K to its Draft Determination).

CitiPower has reviewed all of the matters raised by the AER in its Draft Determination including, in particular, where the AER has made adjustments to CitiPower's Initial Regulatory Proposal. CitiPower has prepared this Revised Regulatory Proposal to be consistent with the Draft Determination, with the exception of deviations that are specifically identified and discussed in the Revised Regulatory Proposal. Where CitiPower has not revised its Initial Regulatory Proposal, the Initial Regulatory Proposal including the relevant attachments and supporting information remains the Current Regulatory Proposal.

The structure of this Revised Regulatory Proposal is as follows:

Chapter	Category
2	Classification of services
3	Control mechanisms for standard control services
4	Growth forecasts
5	Outsourcing arrangements
6	Operating and maintenance expenditure
7	Scale escalation
8	Real cost escalators
9	Forecast capital expenditure
10	Opening asset base
11	Depreciation
12	Cost of capital
13	Estimated corporate income tax
14	Efficiency carryover amounts for 2006-10
15	Efficiency benefit sharing scheme
16	Service target performance incentive scheme
17	Pass throughs
18	Building block revenue requirements
19	Alternative control services (including public lighting)

CitiPower's response to:

- clause 1 of Schedule 1 to the Further RIN is contained in:
  - Attachment 1 to this Revised Regulatory Proposal, titled 'AER Regulatory Information Notice under Division 4 of Part 3', which contains the Revised Regulatory Templates;
  - Attachment 14, titled 'Changes to RIN templates';
  - Attachment 15, titled 'RIN allocators'; and
  - Attachment 16, titled 'Justification for no RIN template information'; and
- clauses 2.1, 2.3 and 2.4 of Schedule 1 to the Further RIN in respect of classification of distribution services, the EBSS, the STPIS and the WACC is contained at the appropriate point in the chapters of this Revised Regulatory Proposal.[40]

[40] CitiPower observes that clause 2.4 of Schedule 1 to the Further RIN would appear to contain a cross-referencing error. Clause 2.4 requires CitiPower to provide all supporting consultant reports *'[f]or each proposed departure identified in response to paragraph 2.2'*. However, clause 2.2 does not require the identification of any proposed departure but rather requires CitiPower to provide an additional set of regulatory templates in relation to any departures identified in response to clause 2.1 of Schedule 1 to the

CitiPower observes, in response to clause 2.1 of Schedule 1 to the Further RIN in respect of the DMIS, that it does not propose any variation or departure from the AER's Draft Determination in respect of the DMIS in this Revised Regulatory Proposal because, as noted above, CitiPower accepts the AER's decision in Chapter 17 of the Draft Determination on the application of the DMIS to it in the 2011-15 regulatory control period.

CitiPower further observes, in response to clause 2.2 of Schedule 1 to the Further RIN, that it does not have anything to produce because CitiPower does not identify any proposed variation or departure in response to clause 2.1 that would result in a change in the information produced in the Revised Regulatory Templates provided in response to clause 1.1 of Schedule 1 to the Further RIN.

As discussed in section 1.3 above, the certification of the reasonableness of the key assumptions underlying the opex and capex forecasts set out in this Revised Regulatory Proposal and the statutory declaration required by the Further RIN are set out in Appendices 1.2 and 1.3 respectively.

This Revised Regulatory Proposal is supported by:

- the detailed information and analysis set out in the appendices to this Revised Regulatory Proposal. This Revised Regulatory Proposal should be read in conjunction with the appendices thereto; and
- the additional documents, information and material contained in the Attachments to this Revised Regulatory Proposal that, together with the documents, information and material previously provided to the AER, substantiate CitiPower's Current Regulatory Proposal - these are provided under cover of this Revised Regulatory Proposal on a USB stick.

An index to these Attachments to the Revised Regulatory Proposal is set out in Appendix 1.4 to this Revised Regulatory Proposal.

1.5 Confidentiality

Clause 6.10.3(d) of the Rules provides that the AER's duty to publish this Revised Regulatory Proposal together with any accompanying information as soon as practicable after receipt by the AER is subject to the provisions of the NEL and the Rules about the disclosure of confidential information.

Section 18 of the NEL provides that section 44AAF of the Trade Practices Act has effect for the purposes of the NEL and the Rules as if it formed part of the NEL. Section 44AF requires the AER to take all reasonable measures to protect from unauthorised use or disclosure information:

Further RIN. CitiPower presumes that clause 2.4 should have instead referred to clause 2.3 of Schedule 1 of the Further RIN. Clause 2.3 requires CitiPower to identify any proposed departure from a WACC parameter value specified in the SoRI. Accordingly, in responding to clause 2.4 of Schedule 1 of the Further RIN in this Revised Regulatory Proposal, CitiPower has proceeded on the basis that this clause requires it to provide all supporting consultant reports in respect of any departure from a WACC parameter value specified in the SoRI proposed in this Revised Regulatory Proposal.

- given to it in confidence in, or in connection with, the performance of its functions or the exercise of its powers; or
- that is obtained by compulsion in the exercise of its powers.

CitiPower claims confidentiality in respect of:

- the information identified in this Revised Regulatory Proposal as confidential by means of yellow shading;
- the appendices to this Revised Regulatory Proposal titled 'Confidential Appendix [x]', which appendices are confidential to the extent identified therein and by means of yellow shading;
- the attachments to the Revised Regulatory Proposal that are identified as confidential in the index to those attachments; and
- any other information and/or documents identified by CitiPower as confidential (whether in this Chapter 1, elsewhere in this Revised Regulatory Proposal or in any other document or correspondence provided by CitiPower).

The information contained in the parts of the Revised Regulatory Proposal set out above is not publicly available and contains either intellectual property or information that is otherwise commercially sensitive.

CitiPower expects that any information in this Revised Regulatory Proposal or the appendices or attachments thereto identified by CitiPower as confidential (whether in this Chapter 1, elsewhere in this Revised Regulatory Proposal or in any other document or correspondence provided by CitiPower) will not be disclosed by the AER except as authorised by section 44AF of the Trade Practices Act or Division 6 of Part 3 of the NEL.

CitiPower requests that, except where disclosure is authorised by section 44AAF of the Trade Practices Act or Division 6 of Part 3 of the NEL, the AER does not disclose the information that CitiPower has identified as subject to a claim of confidentiality to any third party (with the exception only of disclosure to the AER's external expert consultants and legal service representatives for the purpose of making the AER's Final Determination) without first obtaining CitiPower's express and specific written consent.

2. CLASSIFICATION OF SERVICES

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 2 of the AER's Draft Determination regarding the classification of its distribution services for the 2010-15 regulatory control period.

2.1 Summary of key points

In this Revised Regulatory Proposal, CitiPower has accepted the AER's classification of services contained in Chapter 2 of its Draft Determination, except that it has not included the fault level compliance service in its Revised Regulatory Proposal. CitiPower does not currently provide this service and has decided that it will not provide this service if it is classified as an alternative control (fee based) service.

In respect of the reserve feeder service, CitiPower assumes that this service only relates to the operation and maintenance costs associated with the reserve feeder as set out in its Initial Regulatory Proposal, and does not relate to the request for a new reserve feeder. Accordingly, it has prepared this Revised Regulatory Proposal on that basis.

For the purposes of clause 2.1 of the Further RIN, CitiPower observes that it has not varied or departed from the Draft Determination in respect of the classification of a distribution service, except that CitiPower has decided not to provide the fault level compliance service.

2.2 Rule requirements

Clause 6.12.1 of the Rules requires the AER to make a decision on the classification of the services to be provided by the DNSP during the course of the regulatory control period.

Under clause 6.2.2(c) of the Rules, in classifying a direct control service as a standard control service or an alternative control service, the AER must have regard to:

- the potential for development of competition in the relevant market and how the classification might influence that potential;
- the possible effects of the classification on administrative costs of the AER, the DNSP and users or potential users;
- the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made;
- the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction);
- the extent the costs of providing the relevant service are directly attributable to the customer to whom the service is provided; and
- any other relevant factor.

Clause 6.2.2(d) provides that in classifying direct control services that have previously been subject to regulation under the present or earlier legislation, the

AER must act on the basis that, unless a different classification is clearly more appropriate:

- there should be no departure from a previous classification (if the services have been previously classified); and
- if there has been no previous classification, the classification should be consistent with the previously applicable regulatory approach.

2.3 CitiPower's Initial Regulatory Proposal

In Chapter 3 of its Initial Regulatory Proposal, CitiPower described how its distribution services should be classified under the Rules.

In Table 3.2 of its Initial Regulatory Proposal, CitiPower set out how its proposed classification of services differed to the classification of services in the AER's Framework and Approach Paper. This table is repeated below.

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 3.1 Differences between AER's indicative, and CitiPower's proposed, services classification

2.4 AER's Draft Determination

In the Draft Determination, the AER accepted CitiPower's classification of the following services for the 2011-15 regulatory control period:

- connection and augmentation works for new connections. The AER classified this service as a standard control service;
- location of underground cables. The AER classified this service as a standard control service;
- meter investigation. The AER classified this service as an alternative control (fee based) service;
- special meter reading. The AER classified this service as an alternative control (fee based) service;
- PV installation. The AER classified this service as an alternative control (fee based) service;
- energisation of new connections. The AER classified this service as an alternative control (fee based) service;
- repair of damage to overhead service cables caused by high load vehicles. The AER classified this service as an alternative control (quoted) service.

The AER rejected CitiPower's classification of the following services for the 2011-15 regulatory control period:

- auditing design and construction. The AER classified this service as an alternative control (quoted) service;
- specification and design enquiry. The AER classified this service as an alternative control (quoted) service;
- temporary supply services. The AER classified this service as an alternative control (quoted) service;

- coverage of low voltage mains for safety purposes. The AER classified this service as an alternative control (quoted) service;
- elective undergrounding where an above ground service currently exists. The AER classified this service as an alternative control (quoted) service;
- fault level compliance service. The AER classified this service as an alternative control (fee based) service;
- reserve feeder. The AER classified this service as an alternative control (fee based) service;
- provision of watchman lights. The AER said it would treat this service as unclassified;
- repair of watchman lights. The AER said it would treat this service as unclassified;
- re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160MWh. The AER classified this service as an alternative control (fee based) service;
- standard connection/routine connections. The AER classified this service as an alternative control (fee based) service for customer connections below 100 amps and an alternative control (quoted) service for customer connections above 100 amps;
- AMI metering services. The AER said that new services facilitated by AMI would be regulated under the DNSPs' distribution licences and ESCV's Guideline 14;
- unmetered supplies for Type 7 metres. The AER said that this service would be regulated by AMI Order in Council (clause 6).

2.5 CitiPower's response to AER's Draft Determination

CitiPower accepts the AER's classification of services contained in Chapter 2 of its Draft Determination, except that it has not included the fault level compliance service in this Revised Regulatory Proposal. In addition, it makes an observation about the reserve feeder service below.

2.5.1 Reserve feeder service

The reserve feeder service involves operating and maintaining a second source of supply to a customer's premise. In its Initial Regulatory Proposal, CitiPower considered that this service should be classified as a negotiated service.[41] In its Draft Determination, the AER decided to classify this service as an alternative control (fee based) service.[42]

CitiPower accepts the AER's classification of this service. However, it wishes to ensure that, as set out in its Initial Regulatory Proposal, the reserve feeder service only relates to the operation and maintenance costs associated with the reserve

[41] Initial Regulatory Proposal, p22.
[42] AER, Draft Determination, p30.

feeder, and does not relate to the request for a new reserve feeder.[43] A request for a new reserve feeder would be treated as for any other new connection under Electricity Guideline 14.

2.5.2 Fault level compliance service

In its Initial Regulatory Proposal CitiPower proposed that the fault level compliance service should be classified as a standard control service.[44] In its Draft Determination, the AER decided that this service should be classified as an alternative control (fee based) service.[45]

CitiPower does not currently provide this service and has decided that it will not provide this service if it is classified as an alternative control (fee based) service. Accordingly, it has not included this service in its Revised Regulatory Proposal. In the absence of this service all embedded generator connections will be processed under the ESCV's Guideline 14 and the ESCV's Guideline 15.[46]

2.6 CitiPower's Revised Regulatory Proposal

CitiPower has prepared this Revised Regulatory Proposal on the basis of the AER's decision on service classification in its Draft Determination, except that it has not included the fault level compliance service in its Revised Regulatory Proposal.

In addition, CitiPower has prepared its Revised Regulatory Proposal on the basis that the reserve feeder service only relates to the operation and maintenance costs associated with the reserve feeder as set out in its Initial Regulatory Proposal.

[43] Initial Regulatory Proposal, p22.
[44] Initial Regulatory Proposal, p28.
[45] AER, Draft Determination, p29.
[46] Attachment 30 to this Revised Regulatory Proposal.

3. CONTROL MECHANISM FOR STANDARD CONTROL SERVICES

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to:

- Chapter 4 of the Draft Determination regarding control mechanisms for standard control services; and
- Appendices E, F and G of the Draft Determination regarding distribution tariffs, transmission tariffs and assigning customers to tariff classes.

3.1 Summary of key points

3.1.1 Recovery of transmission-related costs

CitiPower considers that the control mechanism should include a term to allow the recovery of:

- transmission connection charges - the charges payable by DNSPs for connection to the transmission system;
- inter-DNSP charges - the inter-network provider distribution service tariffs paid to other DNSPs (net of any similar payments received from other DNSPs); and
- avoided TuOS payments and avoided DuOS payments - the payments that the DNSP is required to make to embedded generators, which comprise avoided TuOS payments under clause 5.5(h) of the Rules and avoided DuOS payments that may be required to be made under CitiPower's distribution license and the ESCV's Guideline 15,

(collectively referred to as **Transmission-related Costs**).

CitiPower does not accept the AER's decision in the Draft Determination not to include any mechanism to allow the recovery of Transmission-related Costs.

CitiPower considers that the AER should include a new term in each of the WAPC formula and the side constraint formula to address the recovery of Transmission-related Costs (TRC_t). If the AER rejects CitiPower's proposed WAPC or side constraint terms (or both of them) regarding transmission-related costs, CitiPower considers that the AER must:

- increase CitiPower's forecast opex to include the estimated amounts of the Transmission-related Costs for 2011-15; and
- accept a 'transmission related costs event' as an additional nominated pass through event covering the difference between forecast and actual expenditure in respect of Transmission-related Costs, with a materiality threshold of zero.

3.1.2 S factor true-up and K factor true-up

CitiPower does not accept the AER's decision not to address the S factor true up in the Draft Determination and to instead leave it to the 2016-20 Distribution

Determination. CitiPower considers that the AER should include a new term in each of the WAPC formula and the side constraint formula to address the S factor true-up (T_t).

CitiPower proposes that an additional term should be added to the WAPC formula and side constraint formula to address the true up of the K_t correction factor under the 2006-10 EDPR, which related to the under and over recovery of transmission revenue.

3.1.3 Formula errors

CitiPower considers that the WAPC and side constraint formulae in the Draft Determination contain errors in relation to:

- calculation of the passthrough factor;
- the left-hand side of the WAPC and side constraint formulae;
- the calculation of the licence fee factor in Appendix E.2; and
- the formula for the correction factor Kzt in the maximum transmission revenue control in Appendix F2.5.

3.1.4 Appendix E: Changes to tariff structures

CitiPower considers that the rules in Appendix E.1 of the Draft Determination regarding changes to tariff structures are not workable in relation to determining the values of q^{ij}_{t-2} and p^{ij}_{t-1}. CitiPower proposes amendments to the rules in relation to those matters.

3.1.5 Appendix G: Tariff reassignment requirements

The AER's proposed reassignment requirements in Appendix G of the Draft Determination are significantly more onerous than the current requirements and will require CitiPower to incur additional costs not contemplated in its Initial Regulatory Proposal.

CitiPower does not accept the AER's requirement in clause 6 of Appendix G to notify customers of any assignment or reassignment. CitiPower considers that this requirement should only apply to reassignment and not initial assignment.

CitiPower considers that the requirement in clause 7 of Appendix G that the EWOV be included in the tariff assignment dispute resolution process is inappropriate and will impose unnecessary additional costs on DNSPs. CitiPower considers that the references to EWOV in this clause should be deleted.

3.2 Rules requirements

Clause 6.12.1 of the Rules details the constituent decisions that must be made by the AER as part of its Final Determination. The decisions that relate to the control mechanism for standard control services are:

- a decision under clause 6.12.1(11) on the control mechanism (including the X factor) for standard control services;
- a decision under clause 6.12.1(13) on how compliance with a relevant control mechanism is to be demonstrated;
- a decision under clause 6.12.1(17) on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another (including any applicable restrictions); and
- a decision under clause 6.12.1(19) on how the DNSP is to report to the AER on its recovery of 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.

In relation to tariff reassignment, clause 6.18.4(a)(4) provides:

> '*a* Distribution Network Service Provider's *decision to assign a customer to a particular* tariff *class, or to re-assign a customer from one* tariff *class to another should be subject to an effective system of assessment and review*.
>
> Note:
>
> If (for example) a customer is assigned (or reassigned) to a tariff class on the basis of the customer's actual or assumed maximum demand, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in maximum demand to a tariff class that is more appropriate to the customer's load profile.'

3.3 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower:

- accepted the position set out in the AER's Framework and Approach Paper that a WAPC form of control should apply to standard control services;
- proposed a mechanism for calculating the licence fee factor in the WAPC, which was not set out in the Framework and Approach Paper;
- proposed adding a passthrough factor to the WAPC;
- proposed adding an S factor true up correction factor to the WAPC;
- proposed that the existing rules in the ESCV's 2006-10 EDPR should be incorporated into the control mechanism in relation to:
    - the treatment of tariff changes when applying the WAPC;
    - the unders and overs mechanism for the recovery of TuOS charges;
    - a G factor for the recovery of embedded generation and other fees; and
    - a D factor for the recovery of inter-DNSP charges.[47]

[47] Initial Regulatory Proposal, pp324-328.

3.4 AER's Draft Determination

The WAPC formula set out in the Draft Determination is as follows:[48]

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\pm(passthrough_t)$$

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^{ij}_t is the proposed distribution tariff for component j of distribution tariff i in regulatory year t;

p^{ij}_{t-1} is the distribution tariff being charged in regulatory year t–1 for component j of distribution tariff i;

q^{ij}_{t-2} 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 Australian Bureau of Statistics for the September 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 Australian Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year t–1;

minus one.'

X_t is the value of X for year t of the regulatory control period as determined by the AER in chapter 18 of the Draft Determination;

[48] AER, Draft Determination, pp69-70.

S_t is the STPIS factor to be applied in regulatory year t;

L_t is the licence fee pass through adjustment to be applied in regulatory year t in accordance with appendix E.2 of the Draft Determination; and

$passthrough_t$ is 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.

The side constraint formula set out in the Draft Determination is as follows:[49]

$$\frac{\sum_{j=1}^{m} d_t^j q_{t-2}^j}{\sum_{j=1}^{m} d_{t-1}^j q_{t-2}^j} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\times(1+2\%)\pm(passthrough_t)$$

Where each tariff class 'j' has up to 'm' components, and where:

d^j_t is the proposed price for component j of the tariff class for year t;

d^j_{t-1} is the price charged by the DNSP for component j of the tariff class in year
t-1;

q^j_{t-2} is the audited quantity of component j of the tariff class that was charged by the DNSP in year t–2;

X_t is the value of X for year t of the regulatory control period as determined by the AER in chapter 18 of the Draft Determination. If X>0, then X will be set equal to zero for the purposes of the side constraint formula;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year t;

L_t is the licence fee pass through adjustment to be applied in regulatory year t;

CPI_t is defined as set out in section 4.6.1 of the Draft Determination; and

$passthrough_t$ is 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.

Appendix E of the Draft Determination sets out rules regarding the treatment of changes to tariff structures when applying the WAPC and side constraint. It also sets out the formula for calculation of the licence fee factor.

Appendix F of the Draft Determination sets out a 'maximum transmission revenue control' and the formulae for implementing that control.

[49] AER, Draft Determination, pp70-71.

Appendix G of the Draft Determination sets out the requirements for assigning customers to tariff classes.

The AER did not accept CitiPower's proposals in relation to:

- an S factor true up correction factor;
- a G factor for the recovery of embedded generation and other fees; or
- a D factor for the recovery of inter-DNSP charges.[50]

3.4.1 Recovery of transmission-related costs

The AER rejected the proposals by the Victorian DNSPs that the Final Determination should provide for the recovery of Transmission-related Costs and PFIT payments.[51]

The AER considered that, unlike TuOS charges, the recovery of these payments was not permitted under clause 6.18.7 of the Rules. On that basis, the AER determined not to address these matters in the Draft Determination.

The AER noted that PFIT Payments were the subject of a current rule change proposal. The AER stated *'[s]ubject to the outcome of this rule change process the AER will consider in the final decision how rebate payments under the PFIT scheme are to be recovered in the forthcoming regulatory control period.'*[52]

The AER also noted that it had been advised that the DNSPs have contacted the AEMC to discuss a rule change proposal for transmission connection charges.[53] The AER suggested that the DNSPs can raise the issue of recovery of inter-DNSP charges and avoided TuOS and avoided DuOS payments with the AEMC as part of that rule change.[54]

The AER stated *'[s]ubject to the outcome of this rule change process the AER will consider in the final decision how these charges are to be recovered in the forthcoming regulatory control period.'*[55] It is unclear whether the AER's comments mean that the AER will take action on these issues in the Final Determination only if the rule change is implemented before the Final Determination, or whether the AER will address this issue in the Final Determination if the rule change is not implemented before the Final Determination.

3.4.2 S factor true up

The AER rejected the proposals by the Victorian DNSPs that the distribution determination should include an S factor true up mechanism. The AER rejected

[50] AER, Draft Determination, pp58-69.
[51] AER, Draft Determination, pp62-66.
[52] AER, Draft Determination, p63.
[53] AER, Draft Determination, p64.
[54] AER, Draft Determination, p66.
[55] AER, Draft Determination, p66. The AER made a similar comment specifically in relation to transmission connection charges on p64.

CitiPower's proposed S factor correction term for the control mechanism on the basis that clause 6.12.3(c) of the Rules constrained the AER's ability to change the form of control from that specified in the Framework and Approach Paper.[56]

The AER stated that the DNSPs will instead be able to recover the S factor true-up amount in the 2016-20 Distribution Determination.[57]

3.4.3 Appendix G: Tariff reassignment requirements

Appendix G of the Draft Determination sets out the requirements for assigning customers to tariff classes.

Clause 6 of Appendix G provides that:

> *'A Victorian DNSP must notify the customer concerned in writing of the tariff class to which the customer has been assigned or re-assigned by it, prior to the assignment or reassignment occurring.'*[58]

Clause 7 of Appendix G requires that the notice under clause 6 must advise the customer of several matters, including that the customer may object to the assignment or reassignment and may escalate the matter to EWOV.

3.5 CitiPower's response to the AER's Draft Determination

3.5.1 Recovery of Transmission-related Costs

3.5.1.1 Additional WAPC and side constraint terms

CitiPower does not accept the AER's rejection of its proposal to add new terms to the WAPC formula to allow the recovery of transmission-related costs.

On 1 July 2010 the AEMC made its PFIT Rule Change.[59] The PFIT Rule Change will allow CitiPower to recover PFIT payments under the new clause 6.18.7A of the Rules. Accordingly, the additional control mechanism terms do not need to address recovery of PFIT Payments.

A rule change proposal by UED on behalf of all of the Victorian DNSPs in relation to transmission connection charges, inter-DNSP charges and avoided TuOS payments was lodged with the AEMC on 24 June 2010.[60] However, the timeframes for a rule change mean that there is almost no prospect that a rule

[56] AER, Draft Determination, p59.
[57] AER, Draft Determination, p59.
[58] AER, Draft Determination Appendices, Appendix G, p21.
[59] AEMC, National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010 No. 7 (Attachment 28 to this Revised Regulatory Proposal). AEMC, Rule Determination, National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010, 1 July 2010 (Attachment 29 to this Revised Regulatory Proposal).
[60] UED, Rule change proposal: Amendment to the distribution pricing proposal provisions of the National Electricity Rules to provide for the explicit inclusion of transmission-related and other relevant charges in a distribution network service provider's pricing proposal, 24 June 2010 (Attachment 27 to this Revised Regulatory Proposal).

change for transmission connection charges, inter-DNSP charges and avoided TuOS payments will be implemented before the date of the Final Determination or before pricing proposals are required to be lodged for the forthcoming regulatory control period.

The AER's decision in the Draft Determination was based on a view that Transmission-related Costs are not covered by clause 6.18.7 of the Rules and that it is not appropriate to allow payments to be recovered under that clause. In making this decision, the AER has asked itself the wrong question.

CitiPower's Initial Regulatory Proposal did not refer to clause 6.18.7. CitiPower proposed that transmission-related costs should be recovered through the control mechanism formula, in a similar manner to how they are recovered under the ESCV's 2006-10 EDPR.

Clause 6.18.7 relates to the pass through of TuOS costs in a DNSP's pricing proposal. Whether Transmission-related Costs are covered by that clause is not determinative of the issue of whether new terms should be added to the WAPC formula. If anything, the fact that these costs cannot be recovered under clause 6.18.7 supports the argument that new WAPC terms should be added, because it shows that there is not a more suitable mechanism for their recovery.

The correct questions that the AER should have asked are:

- does the AER have a power to add a term to the WAPC formula to address the recovery of transmission-related costs; and
- if so, is it consistent with the NEO and the revenue and pricing principles to add such a term.

CitiPower considers that the AER does have a power to add a term to the WAPC to allow the recovery of Transmission-related Costs and that it is consistent with the NEO and the revenue and pricing principles to do so.

CitiPower notes that the AER's reluctance to add the requested terms to the WAPC formula may also be due in part to the comment that the AER makes elsewhere in Chapter 4 of the Draft Determination that clause 6.12.3(c) constrains the AER's ability to amend the form of control. In refusing CitiPower's request for an additional WAPC term to address the S factor true-up, the AER stated that the addition of such a term was not appropriate given those constraints. [61]

This comment by the AER is contrary to the interpretation that the AER has taken to clause 6.12.3(c) in Previous Distribution Determinations. In the South Australian Draft Determination, the AER stated: [62]

[61] AER, Draft Determination, p59.

[62] AER, South Australian Draft Determination, Chapter 4 (Control mechanisms for standard control services) (Attachment 21 to this Revised Regulatory Proposal).

'Clause 6.8.1, in conjunction with clause 6.12.3(c), of the NER does not allow the form of control mechanism that applies to ETSA Utilities to be varied from that specified in the framework and approach (that is a WAPC cannot be changed to a revenue cap). However, the AER considers that the WAPC formula can be amended where this would reflect (or better reflect) the reasoning set out in the framework and approach.'

That comment shows that the AER interpreted clause 6.12.3(c) as preventing the AER from changing the form of control, eg from a WAPC to a revenue cap, but did not prevent it from amending the WAPC formula. The fact that the AER interpreted clause 6.12.3(c) as allowing it to amend the WAPC formula is confirmed by the fact that in the South Australian Final Determination, the AER added a passthrough term to the WAPC formula even though no such term was included in the WAPC formula in the South Australian Framework and Approach Paper.[63]

The AER has also applied a similar interpretation to clause 6.12.3(c) in its other Previous Distribution Determinations and in other sections of its Draft Determination:

- in the Draft Determination, the AER:
  - added a passthrough term, which was not provided for in the Framework and Approach Paper;64
  - changed the CPI definition from the definition that was set out in the Framework and Approach Paper; and
  - changed the definition of the Lt factor from the definition that was set out in the Framework and Approach Paper; and
- in the Queensland Final Determination, the AER added a passthrough term, a transitional term and a C_t term (an adjustment factor related to capital contributions),[65] none of which were provided for in the Queensland Framework and Approach Paper.[66]

If clause 6.12.3(c) does not permit the AER to amend the price control formula from that set out in the Framework and Approach Paper, then each of these decisions by the AER and the South Australian Final Determination were made in breach of the Rules.

CitiPower considers that clause 6.12.3(c) does not prevent the AER from adding a new term to the WAPC formula, and that the AER's interpretation of clause 6.12.3(c) as set out in the South Australian Draft Determination is correct.

[63] AER, South Australian Final Determination, Chapter 4 (Control mechanisms for standard controls services) (Attachment 22 to this Revised Regulatory Proposal)., p26.
[64] AER, South Australian Framework and Approach Paper (Attachment 23 to this Revised Regulatory Proposal).
[65] AER, Queensland Final Determination, Chapter 4 (Control mechanisms for standard control services) (Attachment 24 to this Revised Regulatory Proposal), p27.
[66] AER, Queensland Framework and Approach Paper (Attachment 25 to this Revised Regulatory Proposal).

In light of the above points, CitiPower considers that the AER should include a new term in the WAPC formula to address Transmission-related Costs (TRC_t). This term should allow a DNSP to pass through all Transmission-related Costs. CitiPower's proposed formula for calculating the TRC_t term is set out in Appendix 3.1 of this Revised Regulatory Proposal.

CitiPower considers that the inclusion of this term is necessary to allow the Victorian DNSPs to recover Transmission-related Costs. Subject to the alternative proposal in section 3.5.1.2 below, without this additional term, the DNSPs will incur costs that they cannot recover through any mechanism. It would be inconsistent with the NEO and the revenue and pricing principles in the NEL for the AER to fail to include a mechanism in the Final Determination that allows a DNSP to recover these costs.

In particular, failing to allow the recovery of these costs would be inconsistent with the revenue and pricing principle requirement in clause 7A(2) of the NEL that a DNSP should be provided with a reasonable opportunity to recover at least the efficient costs that it incurs in providing direct control network services and complying with a regulatory obligation or requirement or making a regulatory payment. CitiPower incurs Transmission-related Costs as a result of providing direct control network services and complying with regulatory obligations and requirements. CitiPower is not aware of any concerns by the AER as to the efficiency of these Costs, and notes that the AER has previously approved the calculation of these Costs.

The right-hand side of the side constraint formula in the Draft Determination mirrors the right-hand side of the WAPC formula, except that the side constraint formula adds 'x (1+2%)'. This symmetry is required for the side constraint to operate effectively.

Accordingly, it is necessary to also add the same additional term to the side constraint formula.

3.5.1.2 Revised opex forecasts and additional pass through event if the AER rejects the proposed WAPC or side constraint terms

Forecast expenditure

The amount of Transmission-related Costs that CitiPower incurred in 2009 and the Transmission-related Costs that it forecasts that it will incur in 2010-15 are set out in Table 3.1.

Vendor and Charge description	Type	2009 $ Nominal	2010 $ Nominal	2011 $2011 Real	2012 $2011 Real	2013 $2011 Real	2014 $2011 Real	2015 $2011 Real
SP Ausnet Connection	Connection	7,538,196	6,988,218	7,267,462	7,340,863	7,415,006	7,489,898	7,930,048
SP Ausnet Augmentation	Connection	774,104	717,023	729,004	729,004	729,004	729,004	364,502
Jemena	inter DNSP	2,473,164	2,551,585	2,617,453	2,631,669	2,619,455	2,605,235	2,617,601
United Energy	inter DNSP	1,463,370	373,404	383,043	385,124	383,336	381,255	383,065
Avoided TUOS payments[1]	Embedded Generator	544,317	148,893	148,893	154,464	160,539	165,501	169,694
Total charges		**12,793,151**	**10,779,123**	**11,145,855**	**11,241,124**	**11,307,340**	**11,370,893**	**11,464,910**

[1] Avoided TuOS payments defined as G payment in chapter 6-10 Rules

[2] Feed In Tariff charges are net of opex

Table 3.1 Forecast transmission-related costs

CitiPower considers that the forecast costs for 2011-15 set out in Table 3.1 above need to be included in its opex allowances under the Final Determination if the AER rejects CitiPower's proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs.

If the AER rejects those terms, then CitiPower will incur these Transmission-related Costs and will have no other mechanism to recover these costs. In the Draft Determination, the AER states that these costs cannot be recovered under clause 6.18.7 of the Rules and the AER refuses to allow them to be recovered as a pass through event.[67] Accordingly, CitiPower will have no mechanism to recover these Costs, unless a rule change is implemented prior to the date of the Final Determination.

The PFIT Rule Change was issued on 1 July 2010 and commenced on the same day. That Rule Change was requested by ETSA on 7 October 2009 and took nine months to complete. It is almost certain that the proposed rule change for transmission connection charges, inter-DNSP charges and avoided TuOS payments lodged on 24 June 2010 by UED will not be implemented before the date of the Final Determination or before pricing proposals are required to be lodged for the forthcoming regulatory control period.

CitiPower incurs these Transmission-related Costs as a result of providing direct control network services and complying with regulatory obligations and requirements. Accordingly, this expenditure is required to achieve the opex

[67] AER, Draft Determination, p64.

objectives under clause 6.5.6(a) of the Rules and would be incurred by a prudent operator in CitiPower's circumstances to achieve those objectives.

Accordingly, the AER is required by clause 6.5.6(c) of the Rules to accept this forecast opex if the AER rejects CitiPower's proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs.

In a recently published paper entitled *'Staff observations – cost recovery by DNSPs for connection services and definition of prescribed connection services'*, the AEMC endorsed the view that the Rules allows a DNSP to recover transmission-related costs through its operating expenditure forecasts. In considering the treatment of transmission connection costs under the Rules, the AEMC stated: [68]

> *'Chapter 6 does not specifically prevent a DNSP from submitting a pricing proposal which includes provision for the pass-through of transmission connection charges (unless the distribution determination itself does so). Transmission connection charges could, for example, be regarded as necessarily involved in the provision of standard control services and therefore legitimately included in the DNSP's forecast operating expenditure under clause 6.5.6 of the Rules, thereby forming part of the costs that are recoverable through distribution tariffs (see also cl. 6.15.3).'*

CitiPower considers that the AER is only entitled to refuse to allow this opex if it is certain that these costs can be recovered through another mechanism, which would only occur if:

- the AER accepted CitiPower's proposed WAPC and side constraint terms; or
- rule changes were implemented in relation to each type of Transmission-related Cost prior to the date of the Final Determination.

As the AER stated in its Queensland Final Determination when considering a similar issue in relation to Ergon's PFIT Payments *'it is not possible for the AER to make its decision on the basis of a proposed rule change'*,[69] and the AER must act on the basis of the Rules provisions as they are at the time of its Determination.

Under the transitional provisions in the PFIT Rule Change, if the new Rule had come into force after the date of the Final Determination, the new Rule would not have automatically applied to CitiPower and would not have automatically provided a mechanism for it to recover PFIT Payments in the 2011-15 regulatory control period.

[68] AEMC, AEMC staff observations – cost recovery by DNSPs for connection services and definition of prescribed connection services, 21 June 2010 (Attachment 26 to this Revised Regulatory Proposal), p2.
[69] AER, Queensland Final Determination, Chapter 15 (Pass through arrangements), (Attachment 24 to this Revised Regulatory Proposal), p308.

It is highly likely that any rule change for transmission connection charges, inter-DNSP charges and avoided TuOS and avoided DuOS payments will not come into force until after the date of the Final Determination. It is also highly likely that any such rule change will contain similar transitional provisions to the PFIT Rule Change. Accordingly, any such rule change will not automatically provide a mechanism for CitiPower to recover these payments.

The rule change lodged by UED also does not cover avoided DuOS payments and will not provide a mechanism for the recovery of those payments, unless the proposed rule is amended during the rule change process.

Nominated pass through event

In the Queensland Final Determination, the AER declined to include a control mechanism term to address PFIT Payments. However, the AER determined that it was appropriate to allow Ergon to include estimated opex related to PFIT Payments in its opex forecasts and to include a 'feed-in tariff event' as a nominated pass through event.[70]

This feed-in tariff event is defined as follows: [71]

> '***Feed-in tariff event*** *means a change in the total amount of direct feed-in tariff payments paid by a Qld DNSP in respect of the Qld feed-in tariff scheme. For the purposes of this definition, the change in the amount of the direct tariff payments paid by the DNSP must be calculated as the difference between:*
>
> *a. the amount of direct tariff payments paid by the DNSP in each regulatory year of the next regulatory control period, derived from the metered output of generators subject to the scheme and the applicable feed in tariff rate applying to the metered output; and*
>
> *b. the amount of scheme direct tariff payments which were forecast for the purpose of and included in the Qld distribution determination for each regulatory year of the regulatory control period*
>
> *Relevant direct tariff payments under this pass through mechanism are those paid through the operation of the Electricity Act 1994 (Qld), and any amendments to this act.'*

CitiPower considers that a similar nominated pass through event must be included in its Final Determination if the AER rejects CitiPower's proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs and instead accepts the forecast opex associated with these Costs. This 'transmission

[70] AER, Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), p308.
[71] AER, Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), p311.

related costs event' should cover the difference between forecast and actual expenditure in respect of transmission connection charges, inter-DNSP charges and avoided TuOS and avoided DuOS payments.

CitiPower proposes that the materiality threshold for this pass through event should be set to zero. The purpose of this pass through event is to ensure that CitiPower remains in the same position (and bears the same exposure to risk) that applied under the ESCV's 2006-10 EDPR and that would apply if Transmission-related Costs were recovered by adding a new term to the WAPC formula as proposed by CitiPower.

The ESCV's 2006-10 EDPR contains a K_t term to true-up the difference between estimated and actual revenues and charges for embedded generation fees and inter-DNSP charges. CitiPower's proposed KAY_t term for the WAPC contains a similar true-up mechanism to ensure that there is no under or over recovery by DNSPs of Transmission-related Costs. Both of those mechanisms allow recovery of the full difference between actual and estimated costs and revenues, and do not contain any form of materiality threshold.

If the 'transmission related costs event' does not have a materiality threshold of zero, then the materiality threshold will result in a fundamental reassignment of risk from customers to DNSPs. The AER has not proposed any mechanism to compensate DNSPs for that increase in risk. As discussed in Chapter 17 of this Revised Regulatory Proposal, it is not appropriate for the materiality threshold to result in such a reassignment of risk compared with the position under the ESCV's 2006-10 EDPR.

3.5.2 S factor true up and K factor true up

3.5.2.1 S factor true up

CitiPower does not accept the AER's decision not to include an S factor true up term in the WAPC formula.

As discussed in section 3.5.1.1 above, CitiPower does not agree that clause 6.12.3(c) of the Rules prevents the AER from amending the WAPC formula that was set out in the Framework and Approach Paper. Consistent with Previous Distribution Determinations by the AER, CitiPower considers that clause 6.12.3(c) only prevents the AER changing the form of the control, e.g. from a WAPC to a revenue cap, and does not prevent the AER from amending the WAPC formula.

CitiPower does not consider that it is appropriate for the AER to refuse to deal with this matter in the Final Determination. Although the AER states that it will address this matter in the 2016-20 Distribution Determination, CitiPower has no guarantee that the AER will actually do so in 2016 or that the mechanism that it will apply in 2016 will be suitable.

CitiPower maintains that an S factor true up term (T_t) should be added to the control mechanism. A new section also needs to be added to the Final Determination setting out the formula for calculating the T_t term. CitiPower's proposed formula for calculating the T_t term is set out in Appendix 3.1 of this Revised Regulatory Proposal.

CitiPower also does not agree with the AER's proposed method for calculating the S factor true up amount. CitiPower's proposed methodology for calculating the S factor true up is explained in Chapter 16 of this Revised Regulatory Proposal.

3.5.2.2 K factor true-up

CitiPower proposes that an additional term (KAY_t) should be added to the WAPC formula and side constraint formula to address the true-up of the K_t correction factor under the ESCV's 2006-10 EDPR, which related to the under and over recovery of transmission revenue.

Clause 3.3 of the ESCV's 2006-10 EDPR set out a maximum transmission revenue control.[72] The formula for this control included a K_t factor, which was defined in clause 3.3.3(i) as *'a correction factor to account for the under or over recovery of actual transmission revenue in relation to allowed transmission revenue.'* The formula for calculating K_t is set out in clauses 3.3.3 and 3.3.4 of the ESCV's 2006-10 EDPR and results in an adjustment for the difference between actual and estimated transmission revenue and charges in the two preceding regulatory years.

For similar reasons as the S factor true up, the control mechanism for the Final Determination needs to include a KAY_t term to close out the K factor under the ESCV's 2006-10 EDPR and address any under or over recovery of transmission charges in 2009 and 2010.

A new section also needs to be added to the Final Determination setting out the formula for calculating the KAY_t term. CitiPower's proposed formula for calculating the KAY_t term is set out in Appendix 3.1 of this Revised Regulatory Proposal.

There is no other mechanism for DNSPs to recoup any under recovery of these charges, or for the AER to require DNSPs to amend their future tariffs to address any over recovery of these charges. On 29 June 2010, the AER advised CitiPower that it could not include the K factor true up in its 2011 pricing proposal because it did not fall within clause 6.18.7 of the Rules.[73]

[72] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal).
[73] Email from the AER (Craig Madden) to the Victorian DNSPs entitled 'AER advice - Recovery of avoided TUOS payments', 29 June 2010 (Attachment 33 to this Revised Regulatory Proposal).

3.5.3 Control mechanism formulae

CitiPower considers that the WAPC and side constraint formulae contain several errors.

3.5.3.1 Calculation of the passthrough factor

In the WAPC formula, the AER defines the $passthrough_t$ factor as follows:

> *'$passthrough_t$ is 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'.*[74]

CitiPower considers that this definition is unworkable because the change in approved passthrough expressed in percentage terms will produce an infinite value in any year (year t) where there was no passthrough amount in the previous year (year
t-1). This will be the result of the amount approved for passthrough for year t being divided by zero.

The correct passthrough factor should be determined as a portion of the annual revenue entitlement in a similar manner as the licence fee factor is determined in Appendix E.2 of the Draft Determination, with a mechanism also added to perform a true up between actual and estimated amounts.

The WAPC formula and side constraint formula should be amended by replacing the AER's passthrough component with '$\times (1+P_t)$'.

A new section also needs to be added to the Final Determination setting out the formula for calculating the passthrough factor. CitiPower's proposed formula for calculating the passthrough factor is set out in Appendix 3.1 of this Revised Regulatory Proposal. A worked example of the formula is set out in the Worked Example of Pass-through Factor Model (Attachment 18 to this Revised Regulatory Proposal).

3.5.3.2 Left-hand side of the WAPC and side constraint formulae

CitiPower considers that there is an error in the left-hand side of the WAPC and side constraint formulae.

The p_{t-1} prices and q_{t-2} quantities need to be split between new and old tariffs and components where reassignment occurs and therefore the price should be based on component *i*, of tariff *j*, from mapped component *h* of tariff *g*. This change is necessary to comply with the implications of Appendix E for tariff reassignment.

Additionally, the side constraint formulae in the Draft Determination is ambiguous by referring to rebalancing requirements expressed in 'tariff

[74] AER, Draft Determination, p70.

component' terms (d), when clause 6.18.6 of the Rules clearly provides that the side constraint applies to a 'tariff class'.

Accordingly, CitiPower considers that the left-hand side of the WAPC formula should be:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_{t-2}^{ij}}{\sum_{g=1}^{n}\sum_{h=1}^{m}\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ghij} q_{t-2}^{ghij}}$$

Where:

Tariff i and component j represent the proposed pricing segment in year t; tariff g and component h represent the source pricing segment from year t-1 that has been mapped to tariff i and component j. There are *n* tariffs and up to *m* tariff components in total;

p^{ij}_t is the proposed distribution price for component j of distribution tariff i in regulatory year t;

q^{ij}_{t-2} is the audited quantity from regulatory year t-2 that is mapped to component j of distribution tariff i in regulatory year t. (Note that this quantity may have actually been delivered to other tariffs than i and components than j in year t-2);

p^{ghij}_{t-1} is the distribution price that was charged in regulatory year t–1 for the subset of component j of distribution tariff i that was mapped from the source component h of source tariff g. (Note that $p^{ghij}_{t-1} = p^{gh}_{t-1}$ for all destination tariffs i and components j. If there is no tariff reassignment then g=i and h=j, and $p^{ghij}_{t-1} = p^{ij}_{t-1}$); and

q^{ghij}_{t-2} is the audited quantity from regulatory year t-2 for the subset of component j of distribution tariff i that was mapped from source component h of source tariff g. (If there is no tariff reassignment then g=i and h=j).

The left-hand side of the side constraint formula should be:

$$\frac{\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_t^{cij} q_{t-2}^{cij}}{\sum_{g=1}^{n}\sum_{h=1}^{m}\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_{t-1}^{ghcij} q_{t-2}^{ghcij}}$$

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";

for each tariff class *c*:

tariff i and component j represent the proposed pricing segment in year t; tariff g and component h represent the source pricing segment from year t-1 that has been mapped to tariff i and component j. Each tariff class *c* has n^c tariffs, with up to m^c components. Note that tariff g and component h are not necessarily of the same tariff class as tariff i and component j, if reassignment between classes occurs; Note: source tariff g and component h are summed over all tariff and components from all classes;

p^{cij}_{t} is the proposed distribution price for component j of distribution tariff i in regulatory year t;

q^{cij}_{t-2} is the audited quantity from regulatory year t-2 that is mapped to component j of distribution tariff i in regulatory year t. (Note that this quantity may have actually been delivered to other tariffs than i and components than j in year t-2);

p^{ghcij}_{t-1} is the distribution price that was charged in regulatory year t–1 for the subset of component j of distribution tariff i that was mapped from the source component h of source tariff g. (Note that $p^{ghcij}_{t-1} = p^{gh}_{t-1}$ for all destination tariffs i and components j. If there is no tariff reassignment then g=i and h=j, and $p^{ghcij}_{t-1} = p^{cij}_{t-1}$. Note also that source tariff g and source component h are not necessarily of class c.); and

q^{ghcij}_{t-2} is the audited quantity from regulatory year t-2 for the subset of component j of distribution tariff i that was mapped from source component h of source tariff g. (If there is no tariff reassignment then g=i and h=j). Note that source tariff g and source component h are not necessarily of class c.

3.5.3.3 Calculation of the licence fee factor

In Appendix E.2 of the Draft Determination, the AER has put a 'floor' on the L'_{t-1} value of zero in the first 2 years of the price control period.[75] This floor is an error and will result in an incorrect adjustment factor for L.

It appears that the AER has attempted to mirror the equivalent term from the ESCV's 2006-10 EDPR. However, the floor in the form of the L factor term in the ESCV's 2006-10 EDPR is not relevant for the Final Determination. The floor was included in the 2006-10 EDPR to address the commencement of the L factor. Given that an L factor is already in place, there is no need for the floor in the control mechanism for the Final Determination.

[75] AER, Draft Determination Appendices, Appendix E, p14.

Accordingly, L'_{t-1} should be defined as 'the value of L'_t determined in the calendar year t-1'.

If the AER retains the floor on the L'_{t-1} value, then DNSPs are likely to under or over recover licence fee payments for 2009 and 2010. Accordingly, if the AER rejects CitiPower's proposal and retains the floor, then the AER needs to allow for a true up of the L factor for 2009 and 2010 in a similar manner to the true up of the S factor and the K factor discussed in section 3.5.2 of this Revised Regulatory Proposal.

3.5.3.4 Maximum transmission revenue control, correction factor Kz_t

In Appendix F2.5 of the Draft Determination, the AER sets out the formula for correction factor Kz_t as part of the maximum transmission revenue control.[76]

There is an error in this formula. The reference to TRa_{t-1} in this formula should be TRa_{t-2}.

3.5.4 Appendix E: Changes to tariff structures

Appendix E.1 of the Draft Determination sets out rules regarding the treatment of changes to tariff structures when applying the WAPC and side constraint. CitiPower considers that those rules are not workable in relation to determining the values of q^{ij}_{t-2} and p^{ij}_{t-1}. These issues are more significant for the Victorian DNSPs than in other jurisdictions because there is likely to be a significant reassignment of customers to new tariffs in the forthcoming regulatory control period due to the roll out of AMI meters.

3.5.4.1 Value of q^{ij}_{t-2}

When determining the value of q^{ij}_{t-2}, section E1.1.1 of Appendix E.1 of the Draft Determination states that reasonable estimates should be submitted by the DNSP *'based on the quantities that would have been sold if the new tariff/tariff component had been introduced in year 't-2'.'* However, section E1.1.1 then requires the DNSP to make an assumption that customer load profiles will not change as a result of the reassignment to the new tariff, and requires that the DNSP uses actual audited quantities for the origin tariff/tariff component in year t-2. That assumption is inconsistent with the requirement to use a reasonable estimate of the quantity that would have been sold if the tariff/tariff component had been introduced in year t-2, and it does not reflect reality.

Appendix E.1 requires a DNSP to determine the values of q^{ij}_{t-2} for the origin tariff and new tariff based on the proportion of customers that are reassigned to the new tariff. If there is a customer response to the change in tariff, which is highly likely where customers are reassigned to time of use tariffs following the AMI rollout, these values of q^{ij}_{t-2} will not be realistic estimates.

[76] AER, Draft Determination Appendices, Appendix E, p18.

This issue creates a significant risk that the WAPC and side constraint will result in the DNSP not being able to set prices that allow it to recover its revenue requirement for the relevant regulatory year and all future years in the regulatory control period. The risk of potential under-recovery of revenue will materially decrease the incentives to undertake significant tariff reform. CitiPower considers that the AER should consider these incentives when setting the rules regarding changes to tariff structures and ensure that its determination does not undermine the aims of the AMI rollout.

This requirement in Appendix E.1 is also inconsistent with the pricing principles in clause 6.18.5 of the Rules, which require tariffs to take into account the long run marginal cost for the service, have regard to whether customers are likely to respond to price signals, and ensure recovery of revenue with minimum distortion to efficient patterns of consumption.

CitiPower considers that this problem can be resolved by amending Appendix E.1 of the Draft Determination so that when determining the value of q^{ij}_{t-2}, a DNSP is required to adjust the q^{ij}_{t-2} values by an appropriate elasticity figure that represents the expected demand response for the remainder of the regulatory control period as a result of the reassignment, so as to leave the DNSP in a revenue neutral position. CitiPower considers that it is able to estimate the effects of demand responses with reasonable accuracy.

3.5.4.2 Values of p^{ij}_{t-1}

When determining the value of p^{ij}_{t-1}, section E1.1.2 of Appendix E.1 of the Draft Determination requires the DNSP to set the value of p^{ij}_{t-1} to zero if the origin tariff and the new tariff do not have the same unit of measure.

Setting the value of p^{ij}_{t-1} to zero is not a workable solution to this issue. It will distort the application of the WAPC and side constraint and will prevent those mechanisms from operating as intended. It will create a significant risk that the WAPC and side constraint will result in the DNSP not being able to set prices that allow it to recover its revenue requirement for the relevant regulatory year.

CitiPower expects that the most likely instance where the origin tariff and the new tariff will not have the same unit of measure is where the origin tariff is measured in kW and the new tariff is measured in kVa. This situation can be easily addressed by applying the estimated power factor effects over the remainder of the regulatory control period to convert the kVa value to a kW value.

CitiPower proposes that the AER should amend Appendix E.1 of the Draft Determination to remove the requirement that the value of p^{ij}_{t-1} must be set to zero if the origin tariff and the new tariff do not have the same unit of measure. In such a situation, the Appendix should instead provide that an adjustment should be made using an appropriate conversion factor and taking into account the expected behavioural response over the remainder of the regulatory control period.

3.5.5 Appendix G: Tariff reassignment requirements

3.5.5.1 Tariff reassignment requirements

The AER's proposed reassignment requirements in Appendix G of the Draft Determination are significantly more onerous than the requirements that currently apply. CitiPower expects that these requirements will cause it to incur additional costs that were not contemplated in its Initial Regulatory Proposal.

CitiPower's concerns with the Draft Determination relate to the requirement to notify customers of any assignment or reassignment and the interposition of EWOV in the tariff assignment dispute resolution process.

3.5.5.2 Assignment process

Clause 6 in Appendix G of the Draft Determination requires Victorian DNSPs to notify a customer in writing of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring.

Currently Victorian DNSPs must comply with a similar regulatory obligation under the ESCV's 2006-10 EDPR, which states: [77]

> *'The distribution business must notify the distribution customer concerned in writing of the distribution tariff to which the distribution customer has been reassigned, prior to the reassignment occurring.'*

There are similarities in these clauses. However, by inserting the words 'assigned' and 'assignment' in clause 6 of Appendix G to capture notification for both circumstances, CitiPower considers clause 6 becomes unwieldy.

The words 'has been assigned' and 'prior to the assignment' in clause 6 also appear contradictory. If a DNSP is required to notify the customer of the tariff to which it has been assigned, the DNSP can only do so after the assignment – not prior.

CitiPower considers that there are implementation issues in relation to notification of tariff assignment, but not with reassignment. The issues with notification of tariff assignment are discussed in detail below.

3.5.5.3 Issues with notification of tariff assignment for customer connections

Initial tariff assignment already involves implicit or explicit agreement to a customer's network tariff assignment. The means for this agreement differs between small and large customers, but in both cases customers are afforded the ability to question and/or dispute this initial assignment.

[77] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), clause 2.1.20.

A significant proportion of CitiPower's distribution customers are small customers. Small customers who require new connections generally approach a retailer of their choice and arrange the connections. When a customer enters into a retail contract with their retailer, the retail tariff is inclusive of the DNSP's network tariff, which is bundled into the retail tariff.

Large customers generally negotiate directly with the DNSP on the most suitable network tariff class having regard to their load and connection characteristics. This negotiation takes place at the same time when the customers negotiate the supply connection with the DNSP. It is worth nothing that the connection charge payable by the customer can only be determined after agreement is reached with the customer on the applicable network tariff class. This is because the DNSP must know the future tariff revenue in order to calculate in required up-front connection charge net of expected revenues.

Therefore in all cases, the customers have either implicitly or explicitly agreed to the network tariff and there is no need to for the DNSP to provide notice of tariff assignment.

CitiPower receives approximately 30,000 energisation requests (fuse inserts) each year via the B2B process from retailers. They relate to properties that have been previously connected. Under Clause 6 of Appendix G of the Draft Determination, a DNSP would be required to notify each of these customers of the tariff class to which the customer has been assigned. CitiPower believes the DNSP's notice will only serve to confuse the customers, given the customers have instructed their retailer to arrange energisation, agreed to a retail tariff (inclusive of a network tariff) and entered into a retail contract. Moreover, the written notice will be marked attention to 'The Customer' because not all retailers provide the customer's name on the B2B service orders.

The distribution tariff on the DNSP's assignment notice to the customer will not match the retail tariff. CitiPower believes this confusion will lead to customers calling their retailer and/or the DNSP that sent the tariff assignment notice. CitiPower estimates that about 10 per cent of customers will call to enquire why the DNSP has sent them the information and question why that information cannot be reconciled with their retail bill.

3.5.5.4 CitiPower's proposed solution to avoid unnecessary and inefficient costs

CitiPower proposes a way forward that avoids unnecessary costs. In CitiPower's view, an effective system of assessment and review is only required when a customer's tariff is reassigned by the DNSP to another existing or new tariff in accordance with Appendix G.

CitiPower proposes that clause 6 of Appendix G should be amended as follows:

'(a) A Victorian DNSP must notify the customer concerned in writing of the tariff class to which the customer will be ~~has been~~ ~~assigned or~~ re-assigned by it, prior to the ~~assignment or~~ reassignment occurring.

(b) A customer may apply for reassignment of their tariff class.'

If the AER does not make this amendment in the Final Determination, it must compensate CitiPower for the additional costs that it will incur by allowing a step change, as set out in Chapter 6 of this Revised Regulatory Proposal.

3.5.5.5 Dispute resolution through EWOV

The AER's Draft Determination alters the current tariff reassignment dispute resolution process without reason and with the likely effect of imposing significant additional costs on DNSPs and EWOV.

The current process set out in the ESCV's 2006-10 EDPR is: [78]

'2.1.25 If a distribution customer disagrees with the distribution tariff to which that distribution customer has been assigned, then that distribution customer may give a written notice to the Commission and the distribution business requesting that they be reassigned.

2.1.26 (i) If the Commission receives a notice under clause 2.1.25, then it must decide which of the distribution business's distribution tariffs the distribution customer giving the notice under clause 2.1.25 should be assigned to, taking into account:

(a) the distribution customer's load and connection characteristics;

(b) whether the distribution customer has an interval meter installed; and

(c) the distribution tariffs to which other distribution customers with the same or materially similar load and connection characteristics, and the same or materially similar meter, have been assigned.

(ii) The Commission must notify the distribution customer giving the notice under clause 2.1.25 and the distribution business concerned in writing of its decision and the date from which its decision should be applied.

2.1.27 If the Commission does not give a written notice under clause 2.1.26(ii) within 30 business days of receiving the relevant notice under clause 2.1.25, then the Commission is to be regarded as having decided that the distribution customer giving the relevant notice under clause 2.1.25 should not be reassigned.

[78] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), clauses 2.1.25 to 2.1.28.

> *2.1.28 A distribution business must comply with a decision by the Commission under clause 2.1.26 in relation to a distribution customer.'*

This process does not contemplate EWOV involvement primarily because:

- the AER is the economic regulator responsible for enforcement of price determinations applicable to Victorian DNSPs;
- EWOV is not resourced to handle network tariff assignment complaints; and
- DNSPs incur a fee of $790 each time a customer escalates a complaint with EWOV. These costs are not currently incurred and, accordingly, are not included in CitiPower's base year opex.

CitiPower does not see any value in altering the existing process given that this would add costs and potentially increase customer confusion relative to current practice.

3.6 CitiPower's Revised Regulatory Proposal

3.6.1 WAPC formula

CitiPower amends its Initial Regulatory Proposal and proposes that the formula for the control mechanism for standard control services should be as follows:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_{t-2}^{ij}}{\sum_{g=1}^{n}\sum_{h=1}^{m}\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ghij} q_{t-2}^{ghij}} \leq (1+\mathrm{CPI}_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\times(1+T_t)\times(1+TRC_t)\times(1+KAY_t)\times(1+P_t)$$

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"*;

tariff i and component j represent the proposed pricing segment in *regulatory year t*; tariff g and component h represent the source pricing segment from *regulatory year t-1* that has been mapped to tariff i and component j. There are *n* tariffs and up to *m* tariff components in total;

p^{ij}_t is the proposed distribution price for component j of distribution tariff i in *regulatory year t*;

q^{ij}_{t-2} is the audited quantity from *regulatory year t-2* that is mapped to component j of distribution tariff i in *regulatory year t*. (Note that this quantity may have actually been delivered to other tariffs than i and components than j in *regulatory year t-2*);

p^{ghij}_{t-1} is the distribution price that was charged in *regulatory year t–1* for the subset of component j of distribution tariff i that was mapped from the source component h of source tariff g. (Note that $p^{ghij}_{t-1} = p^{gh}_{t-1}$ for all destination tariffs i and components j. If there is no tariff reassignment then g=i and h=j, and $p^{ghij}_{t-1} = p^{ij}_{t-1}$);

q^{ghij}_{t-2} is the audited quantity from *regulatory year t-2* for the subset of component j of distribution tariff i that was mapped from source component h of source tariff g. (If there is no tariff reassignment then g=i and h=j);

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 September 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 September Quarter immediately preceding the start of *regulatory year t–1*;
>
> minus one.

X_t is the value of X for *regulatory year t* of the regulatory control period as determined by the AER;

S_t is the Service Target Performance Incentive Scheme factor to be applied in *regulatory year t*;

L_t is the licence fee pass through adjustment to be applied in *regulatory year t* (calculated as discussed in section 3.5.3.3 of this Revised Regulatory Proposal);

T_t is a factor applied in 2012 to recover a correction amount to close out the service incentive scheme under the ESCV's 2006-10 EDPR (calculated in accordance with Appendix 3.1 of this Revised Regulatory Proposal);

TRC_t is the factor representing the amount paid by the DNSP in relation to premium feed-in tariff scheme payments, transmission connection charges, inter-DNSP charges (net of any payments received from other DNSPs) and avoided TUOS and avoided DUOS payments as approved by the AER (calculated in accordance with Appendix 3.1 of this Revised Regulatory Proposal);

KAY_t is a factor to be applied in 2011 and 2012 to recover a correction amount to close out the maximum transmission revenue control under the ESCV's 2006-10 EDPR (calculated in accordance with Appendix 3.1 of this Revised Regulatory Proposal); and

P_t is the change in approved pass through amounts, expressed in percentage form; it is the amount of the approved pass through adjustment to be applied in *regulatory year t* (calculated in accordance with Appendix 3.1 of this Revised Regulatory Proposal).

3.6.2 Side constraint formula

CitiPower amends its Initial Regulatory Proposal and proposes that the side constraint for standard control services should be as follows:

$$\frac{\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_t^{cij} q_{t-2}^{cij}}{\sum_{g=1}^{n}\sum_{h=1}^{m}\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_{t-1}^{ghcij} q_{t-2}^{ghcij}} \le (1+\mathrm{CPI})\times(1-X_t)\times(1+S_t)\times(1+L_t)\times(1+T_t)\times(1+TRC_t)\times(1+KAY_t)\times(1.02)\times(1+P_t)$$

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";

for each tariff class *c*:

tariff i and component j represent the proposed pricing segment in year t; tariff g and component h represent the source pricing segment from year t-1 that has been mapped to tariff i and component j. Each tariff class *c* has n^c tariffs, with up to m^c components. (Note that tariff g and component h are not necessarily of the same tariff class as tariff i and component j, if reassignment between classes occurs. Note also source tariff g and component h are summed over all tariff and components from all classes.);

p^{cij}_t is the proposed distribution price for component j of distribution tariff i in regulatory year t;

q^{cij}_{t-2} is the audited quantity from regulatory year t-2 that is mapped to component j of distribution tariff i in regulatory year t. (Note that this quantity may have actually been delivered to other tariffs than i and components than j in year t-2);

p^{ghcij}_{t-1} is the distribution price that was charged in regulatory year t–1 for the subset of component j of distribution tariff i that was mapped from the source component h of source tariff g. (Note that $p^{ghcij}{}_{t-1} = p^{gh}{}_{t-1}$ for all destination tariffs i and components j. If there is no tariff reassignment then g=i and h=j, and $p^{ghcij}{}_{t-1} = p^{cij}{}_{t-1}$);

$q^{ghcij}{}_{t-2}$ is the audited quantity from regulatory year t-2 for the subset of component j of distribution tariff i that was mapped from source component h of source tariff g. (If there is no tariff reassignment then g=i and h=j. Note also that source tariff g and source component h are not necessarily of class c.);

X_t is the value of X for year t of the regulatory control period as determined by the AER. If X>0, then X will be set equal to zero for the purposes of the side constraint formula;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year t;

L_t is defined as set out in the WAPC formula;

CPI_t is defined as set out in the WAPC formula;

T_t is defined as set out in the WAPC formula;

TRC_t is defined as set out in the WAPC formula;

KAY_t is defined as set out in the WAPC formula; and

P_t is defined as set out in the WAPC formula.

3.6.3 Revised opex forecasts and additional pass through event if the AER rejects the proposed WAPC or side constraint terms

CitiPower amends its Initial Regulatory Proposal and proposes that if the AER rejects CitiPower's proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs (TRC_t), the AER must:

- increase CitiPower's forecast opex to include the estimated amounts of the transmission-related costs set out in Table 3.1 for each of the regulatory years 2011-15; and
- accept a 'transmission related costs event' as an additional nominated pass through event covering the difference between forecast and actual expenditure in respect of transmission connection charges, inter-DNSP charges and avoided TuOS and avoided DuOS payments, with a materiality threshold of zero.

3.6.4 Appendix G: Tariff reassignment requirements

CitiPower proposes that clause 6 of Appendix G of the Draft Determination should be amended as follows:

'(a) A Victorian DNSP must notify the customer concerned in writing of the tariff class to which the customer will be ~~has been~~ ~~assigned or~~ re-assigned by it, prior to the ~~assignment or~~ reassignment occurring.

(b) A customer may apply for reassignment of their tariff class.'

CitiPower proposes that Appendix G of the Draft Determination should be amended to delete clause 7.b and the reference in clause 7.c to 'and the ombudsman scheme noted in clause 7.b'.

If the AER does not accept these amendments, then CitiPower proposes an additional step change to cover the costs of compliance with these requirements, as set out in Chapter 6 of this Revised Regulatory Proposal.

4. GROWTH FORECASTS

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 5 of the AER's Draft Determination regarding CitiPower's growth forecasts (that is, its forecasts of energy consumption, maximum demand and customer numbers for standard control services) for the next regulatory control period.

4.1 Summary of key points

4.1.1 Energy consumption forecasts

CitiPower does not accept the AER's forecasts of energy consumption, substituted in the Draft Determination for those in CitiPower's Initial Regulatory Proposal.

In this Revised Regulatory Proposal, CitiPower adopts revised energy consumption forecasts prepared by NIEIR that reflect updated forecasts of economic growth and forecasts of population growth consistent with the population growth forecasts that the AER's consultant, ACIL Tasman (and thus the AER) recommended be used.

However, CitiPower rejects the AER's conclusions, based on the advice of ACIL Tasman, regarding the policy adjustments to energy consumption forecasts. Policy adjustments are required to ensure that recent or upcoming technological or policy changes that are not reflected in historical relationships are reflected in the forecasts. CitiPower explains the updates to NIEIR's policy adjustments that have occurred to reflect recent policy developments, responds to the AER's and ACIL Tasman's issues and concerns and adduces a further expert report by Frontier that supports the policy adjustments made by NIEIR in updating its energy consumption forecasts.

4.1.2 Maximum demand forecasts

CitiPower does not accept the AER's forecasts of maximum demand, substituted in the Draft Determination for those in CitiPower's Initial Regulatory Proposal.

CitiPower responds to the AER's concerns regarding its maximum demand forecasts in its Initial Regulatory Proposal by:

- explaining why, contrary to the AER's analysis, CitiPower's internal spatial demand forecasts have been demonstrated historically to have a high degree of accuracy;
- updating its own internal spatial maximum demand forecasts to reflect lower than expected maximum demand in 2009-10 in four zone substations;
- providing revised NIEIR forecasts of system maximum demand that are updated for currency and reflect corrections to the data underpinning

NIEIR's November 2009 forecasts (provided with CitiPower's Initial Regulatory Proposal); and

- reconciling CitiPower's updated internal spatial maximum demand forecasts with these revised NIEIR forecasts of system maximum demand. As CitiPower's updated internal spatial maximum demand forecasts are consistent with NIEIR's revised forecasts, CitiPower has not made any adjustments to its internal spatial maximum demand forecasts in this Revised Regulatory Proposal.

4.1.3 Customer numbers forecasts

CitiPower has addressed the concerns raised by the AER regarding its customer number forecasts in respect of economic and population growth by adopting updated NIEIR customer number forecasts that reflect updated forecasts of economic growth and population growth consistent with the population growth forecasts that ACIL Tasman and the AER recommended be used.

4.2 Rule requirements

CitiPower uses forecasts of maximum demand and customer numbers in preparing its opex and capex forecasts for the 2011-15 regulatory control period. Accordingly, the provisions of the Rules governing the opex and capex forecasts (detailed in Chapters 6 and 9 of this Revised Regulatory Proposal respectively) are applicable.

Of particular relevance for the AER's consideration of CitiPower's maximum demand forecasts is that the AER must accept a DNSP's opex and capex forecasts if it is satisfied that the total forecast reasonably reflects (among other things) '*a realistic expectation of the demand forecast … required to achieve the [opex or capex objectives, as relevant]*' (see clauses 6.5.6(c)(3) and 6.5.7(c))(3) of the Rules). In addition, the Rules allow for opex and capex required to meet or manage the expected demand for standard control services (clauses 6.5.6(a)(1), 6.5.6(c)(1), 6.5.7(a)(1) and 6.5.7(c)(1) of the Rules).

By contrast, CitiPower uses the forecasts of energy consumption in applying the control mechanism and setting prices for standard control services. As a result, in making its Final Determination, the AER must determine an 'appropriate' amount in accordance with clause 6.12.1(10) of the Rules.

In its Draft Determination, the AER states that:[79]

> *'Clause 6.12.1(10) of the NER requires the AER to make a decision on appropriate amounts, values or inputs. These include forecasts of peak demand, energy consumption and customer numbers which are inputs to the capex and opex assessments, and the PTRM and subsequently X factors.'*

However, clause 6.12.1(10) of the Rules does not necessarily apply to all of the growth forecasts proposed by CitiPower. For example, given:

[79] AER, Draft Determination, p73.

- CitiPower's maximum demand forecasts are used solely for the purposes of forecasting the capex and opex required in the next regulatory control period; and
- the AER must make an assessment as to whether it accepts the total capex and opex forecasts proposed by CitiPower under clauses 6.12.1(3) and 6.12.1(4) of the Rules,

the maximum demand forecasts cannot be considered 'other' amounts for the purposes of clause 6.12.1(10) of the Rules. The AER must accept the total capex and opex forecasts if it is satisfied that they reasonably reflect the capex and opex criteria (including that they reflect a realistic expectation of the demand forecast required to achieve the capex or opex objectives), and may only adjust the forecast to the extent it is not so satisfied. The AER is not permitted under the Rules to substitute maximum demand forecasts it considers 'appropriate'.

Similarly, where customer number forecasts are used as a basis for forecasting new customer connections capex, the AER is required under the Rules to consider the total forecast capex against the capex criteria and cannot rely on clause 6.12.1(10) of the Rules to substitute customer number forecasts it considers appropriate.

4.3 Energy consumption forecasts

4.3.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower adopted the energy consumption forecasts (including policy adjustments) prepared by NIEIR, which were set out in the report titled Electricity sales and customer number projections for the CitiPower region to 2019.[80]

4.3.2 AER's Draft Determination

The AER rejected the energy consumption forecasts included in CitiPower's Initial Regulatory Proposal and substituted its own forecasts. The AER commented that the incentives of the weighted average price cap form of control (i.e. to understate energy consumption forecasts) may have affected CitiPower's energy consumption forecasts.[81] The reasons for the AER's rejection of CitiPower's energy consumption forecasts, and the forecasts substituted by the AER, are discussed in more detail below.

4.3.2.1 NIEIR's methodology

While the AER agreed with ACIL Tasman's concerns regarding the lack of transparency provided by NIEIR in respect of its energy forecasting methodology, the AER concluded that NIEIR's approach to forecasting energy consumption generally exhibits elements of good forecasting and appears to be reasonable.[82] The AER considered that NIEIR's industry based approach to forecasting energy

[80] Attachment P0005 to the Initial Regulatory Proposal.
[81] AER, Draft Determination, p84.
[82] AER, Draft Determination, pp98-9.

consumption is likely to produce forecasts that are as accurate, if not more accurate, than forecasts simply based on total state or regional economic growth.[83]

4.3.2.2 Input assumptions

ACIL Tasman and the AER raised concerns regarding two of the input assumptions used by NIEIR in forecasting energy consumption:

- population growth; and
- economic growth.

After comparing NIEIR's population growth forecasts to forecasts prepared by the Victorian Treasury and the ABS, ACIL Tasman considered that NIEIR's population growth estimates were '*unreasonably pessimistic*'.[84] ACIL Tasman recommended that NIEIR's population growth forecasts be replaced with the ABS' 'B series' population forecasts.[85] The AER agreed.[86]

ACIL Tasman also recommended, and the AER agreed, that NIEIR's economic growth forecasts should be updated with a more recent set of economic growth forecasts.[87]

4.3.2.3 Policy adjustments

ACIL Tasman and the AER expressed concerns regarding a number of the policy adjustments implicit in, or made to, NIEIR's energy consumption forecasts.

In light of the Federal Government's deferral of the CPRS until after the current commitment period of the Kyoto Protocol, the AER considered that NIEIR's forecasts should be adjusted to reflect this.[88]

In addition, based on ACIL Tasman's recommendations, the AER removed the post model adjustments made by NIEIR for four policies:[89]

- the insulation rebate program;
- the one watt standby target;
- MEPS for lighting; and
- the AMI roll-out.

Each of these policy adjustments is discussed in turn below.

[83] AER, Draft Determination, p98.
[84] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp13-4.
[85] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp13-4, and 80.
[86] AER, Draft Determination, p156.
[87] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p89; AER, Draft Determination, p156.
[88] AER, Draft Determination, pp116-17, and 156.
[89] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp28, 31, 33 and 56; AER, Draft Determination, pp120-1.

Insulation rebate program

The forecasts of energy consumption included in the Initial Regulatory Proposal were prepared prior to the Federal Government's cancellation of the insulation scheme. The AER therefore concluded that NIEIR's adjustment relating to the scheme should be removed.[90]

One watt standby target

On the basis that it could not identify what policy regarding standby power was being modelled by NIEIR, ACIL Tasman recommended reversing NIEIR's adjustment to energy consumption forecasts for the one watt standby target.[91] ACIL Tasman noted that its conclusion was '*strengthened by the fact that a number of MEPS with one watt standby components are already in place and are thus already influencing the data that feeds NIEIR's electricity sales model.*'[92] The AER adopted ACIL Tasman's recommendation.[93]

Lighting MEPS

ACIL Tasman recommended that the post model adjustment for lighting MEPS be reduced to no more than the level of the impact estimated by the Federal Government's Lighting RIS.[94] It did so on the basis that, while the Government was forecasting the total impact of replacing all non-compliant lamps in Australia with MEPS-compliant lighting, the policy adjustments made to NIEIR's energy consumption forecasts should reflect the impact of MEPS-compliant lighting that is likely to occur as a result of MEPS (i.e. a subset of the total impact of a move to MEPS-compliant lighting).[95] The AER agreed and adopted ACIL Tasman's recommendation in its Draft Determination.[96]

AMI roll-out and TOU Tariffs

Arguing that the Victorian Government's moratorium on the TOU Tariffs introduces uncertainty, ACIL Tasman recommended that the AER remove the adjustments to energy consumption made by NIEIR for the AMI roll-out.[97] ACIL Tasman recommended that the AER remove the adjustments '*with a view to making any necessary adjustments as and when the future of AMI meters becomes clearer*.'[98]

Moratorium aside, ACIL Tasman did not agree with the levels of the adjustments for the AMI roll-out made by NIEIR. ACIL Tasman considered that the effect of

[90] AER, Draft Determination, pp120-1.
[91] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp30-1.
[92] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p31.
[93] AER, Draft Determination, p120.
[94] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p28.
[95] ACIL Tasman, *Victorian* Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p26.
[96] AER, Draft Determination, p114.
[97] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p56.
[98] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p56.

TOU Tariffs (which are enabled by AMI) would be muted because it would impact on only one of the components of customer bills.

The AER, however, rejected adjustments to energy consumption for the AMI roll-out and TOU tariffs based on the following:[99]

- the inconsistent approach adopted by NIEIR with respect to determining the impact of AMI on energy consumption and maximum demand forecasts;
- the uncertainty around the introduction of TOU Tariffs; and
- impediments to the implementation of AMI and TOU Tariffs.

The AER's reasoning in its Draft Determination is discussed further below.

4.3.3 CitiPower's response to the AER's Draft Determination

4.3.3.1 Summary

CitiPower does not accept the AER's forecasts of energy consumption, substituted in the Draft Determination for those in CitiPower's Initial Regulatory Proposal.

Pursuant to the Draft Determination, CitiPower engaged NIEIR to produce updated forecasts of energy consumption over the next regulatory control period. These forecasts are set out in NIEIR's report, Electricity sales and customer number projections for the CitiPower region to 2019[100], June 2010. CitiPower submits these forecasts are appropriate.

CitiPower rejects the AER's suggestion that the incentives of the weighted average price cap form of control (i.e. to understate energy consumption forecasts) have affected CitiPower's energy consumption forecasts.[101] CitiPower's energy consumption forecasts were prepared by the independent expert NIEIR. In making these comments, the AER is inferring that NIEIR lacks independence and/or integrity. CitiPower notes that the AER does not appear to rely on any evidence in support of such a finding.

Further, the AER should accept NIEIR's revised forecasts of energy consumption included in the Revised Regulatory Proposal because:

- as accepted by the AER, NIEIR's methodology for forecasting energy consumption is reasonable;
- the AER should be satisfied that the macro-economic indicators forecast by NIEIR are reasonable:
    - NIEIR's updated population growth forecasts are consistent with the ABS' 'series B' population growth forecasts (recommended by ACIL Tasman and the AER); and
    - NIEIR's forecasts reflect updated forecasts of economic growth; and

[99] AER, Draft Determination, pp148-55.
[100] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p85 (Table 7.1).
[101] AER, Draft Determination, p84.

- NIEIR's policy adjustments are appropriate:
    - consistent with the AER's Draft Determination, NIEIR's forecasts assume that the CPRS will be delayed until 1 January 2013; and
    - the overall level of the policy adjustments made by NIEIR are consistent with the level determined by a second independent expert, Frontier.

CitiPower also submits that the AER cannot rely on the alternative forecasts presented in its Draft Determination (from VENCorp and ACIL Tasman).

4.3.3.2 NIEIR's methodology

Subsequent to submitting the Initial Regulatory Proposal, in order to increase the transparency of NIEIR's methodology and to offer the AER additional comfort in respect of the methodology, CitiPower sought from independent experts and provided to the AER (on 28 April 2010) the following:

- a report prepared by NIEIR, Overview of economic and energy forecasting methodologies used at the National Institute of Economic and Industry Research, April 2010; and
- a report by Frontier, Review of NIEIR's methodology for forecasting electricity consumption, prepared for CitiPower, April 2010.

The AER indicated in its Draft Determination that, given the time available, it had not considered the additional information provided by CitiPower for the purposes of the Draft Determination but would consider it in making its Final Determination.[102]

NIEIR's report provides comprehensive discussion of NIEIR's energy consumption forecasting modelling and estimation processes.

Frontier was engaged by CitiPower to assess the reasonableness of the methodology used by NIEIR to prepare its energy consumption forecasts.[103] Frontier concluded that the capabilities of NIEIR's modelling system meet world best practice standards.[104] While the AER's own consultant, ACIL Tasman, does not refer to Frontier's findings in its review of NIEIR's energy consumption forecasts, ACIL Tasman concluded that NIEIR's approach to forecasting electricity consumption includes a number of the features that are necessary and desirable in any energy consumption forecasting process and is generally

[102] AER, Draft Determination, p94.

[103] Footnote 6 in Frontier's report, Review of NIEIR's methodology for forecasting electricity consumption, April 2010 (provided to the AER by email on 28 April 2010), states that 'electricity sales' and 'electricity consumption' are used interchangeably in that report. While NIEIR's detailed methodology report was not completed in time to allow Frontier to incorporate it into its report on the reasonableness of NIEIR's methodology, Frontier sent CitiPower a letter dated 10 May 2010 indicating that it sees no conflict between NIEIR's overview of its methodology of April 2010 and its report, and confirms its conclusions remain unchanged in light of the additional NIEIR methodology document (Attachment 35 to this Revised Regulatory Proposal).

[104] Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010 (provided to the AER by email on 28 April 2010), pii.

sound.[105] As a result, ACIL Tasman did not recommend the use of an alternative model.

The AER therefore has sufficient material before it to conclude that NIEIR's energy consumption forecasting methodology is appropriate.

4.3.3.3 Macro-economic indicators

As noted above, ACIL Tasman and the AER raised concerns regarding two of the macro-economic indicators used by NIEIR in forecasting energy consumption:

- population growth; and
- economic growth.

Population growth

The updated energy consumption forecasts prepared by NIEIR reflect an average population growth forecast across Victoria in the next regulatory control period of 1.4 per cent.[106] This is consistent with the ABS' 'series B' population forecast that ACIL Tasman recommended for use in forecasting energy consumption.[107]

As NIEIR's population growth assumption is now consistent with the ABS' 'series B' population growth forecast, no population adjustment should be made by the AER to CitiPower's energy consumption forecasts reflected in this Revised Regulatory Proposal.

CitiPower notes for completeness, however, that ACIL Tasman's approximation of the impact on energy consumption from an increase in the population growth rate is not an appropriate basis on which to adjust NIEIR's energy consumption forecasts. This is because:

- contrary to its recommendation that the ABS' 'series B' population growth forecast should be used, ACIL Tasman's approximation is based on the ABS' 'series A' (which reflects a more positive outlook for population growth than 'series B');[108] and
- the methodology adopted by ACIL Tasman for estimating the impact of the increase in population growth is flawed.

CitiPower engaged Frontier to review the methodology applied by ACIL Tasman for estimating the impact of a shift from NIEIR's assumptions in its November 2009 forecasts to the ABS' population growth forecasts.

Frontier noted that the calculation of ACIL Tasman's estimates is not clear from the description of the methodology in ACIL Tasman's report, but can be deduced

[105] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p10.
[106] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p28.
[107] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp13-4.
[108] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15; ACIL Tasman, population adjustment spreadsheet (provided to CitiPower by the AER by email on 16 June 2010).

from the workbook provided to CitiPower by the AER.[109] Frontier found that ACIL Tasman's approach to estimating the impact was flawed primarily because ACIL Tasman assumes a constant per capita energy use.[110] As was acknowledged by ACIL Tasman, this does not account for:[111]

- changes in the key drivers of energy consumption, including economic growth and weather (ACIL Tasman only accounts for population as a key driver); or
- policy adjustments that affect energy consumption.

Frontier also observed that ACIL Tasman's approach is inconsistent with the principles of best practice that ACIL Tasman describes in chapter 2 of its report.[112] Specifically, ACIL Tasman's approach does not test or validate its results.[113]

The AER should therefore not rely on ACIL Tasman's population growth adjustment for the purposes of its Final Determination. ACIL Tasman effectively acknowledged this in its report, indicating that the shortcomings in its approach would be addressed by using the ABS' 'series B' population growth forecast and NIEIR's model to produce fresh forecasts.[114] As discussed above, given the population growth forecast underpinning NIEIR's updated energy consumption forecasts is consistent with the ABS' 'series B' population growth forecast, the AER does not need to rely on ACIL Tasman's estimation of the impact of a change in population growth for the purposes of its Final Determination but can rely on the energy consumption forecasts produced by NIEIR.

Economic growth

The updated energy consumption forecasts prepared by NIEIR and incorporated into CitiPower's Revised Regulatory Proposal, reflect GSP forecasts that take into account recent economic conditions.[115]

While in November 2009 NIEIR considered there would be relatively slow economic growth virtually across the entire period in Victoria in 2011-15,[116]

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[109] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15; ACIL Tasman, population adjustment spreadsheet (provided to CitiPower by the AER by email on 16 June 2010).

[110] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15.

[111] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), pp15-6; ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p14.

[112] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15.

[113] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p16.

[114] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp14-5.

[115] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), pp26-30.

[116] NIEIR, Electricity sales and customer number projections for the CitiPower region to 2019, November 2009 (Attachment P0005 to the Initial Regulatory Proposal), p21.

NIEIR indicated in its June 2010 report that growth was expected to be stronger, particularly in the early part of the next regulatory control period.[117]

CitiPower notes that NIEIR's updated forecasts are broadly consistent with the forecasts from the Victorian Treasury. This is shown in Figure 4.1 below.

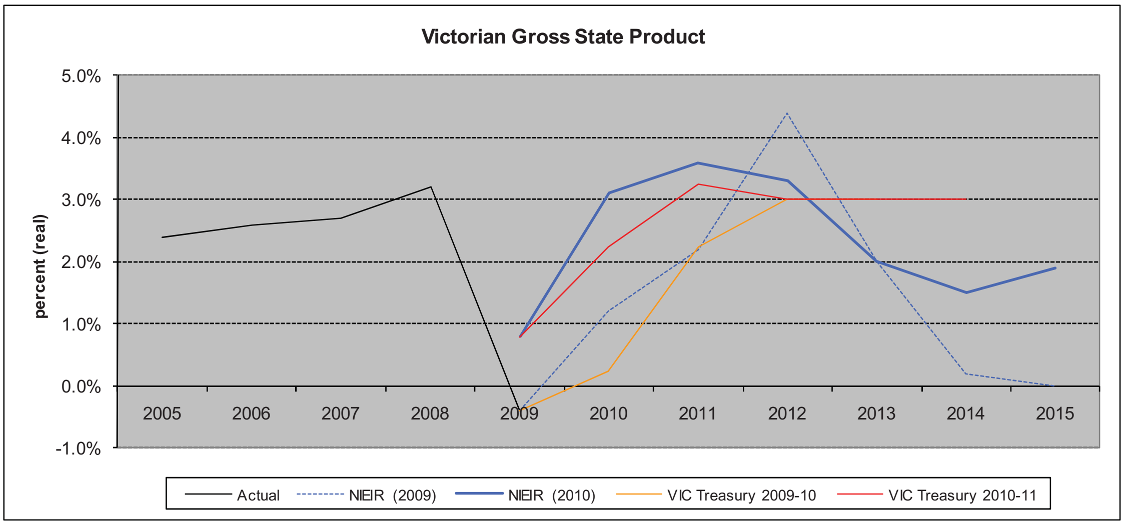

Figure 4.1 Forecasts of Victorian GSP by NIEIR and the Victorian Treasury

4.3.3.4 Policy adjustments

Policy adjustments to energy consumption forecasts are required to ensure that recent or upcoming technological or policy changes that are not reflected in historical relationships are captured in the forecast.[118]

As noted above, the AER considered that NIEIR's forecasts should be adjusted to reflect the Federal Government's deferral of the CPRS. While the AER indicated that NIEIR should *'amend the CPRS policy assumption to delay the commencement of the CPRS by 6 months, to 1 January 2012'*, CitiPower assumes the AER intended the delay to be until 1 January 2013. NIEIR's updated energy consumption forecasts reflect this.[119] As a result, the AER's previous basis for concern in respect of NIEIR's CPRS assumptions has been addressed.

The level of the reduction in energy consumption due to post model adjustments reflected in NIEIR's revised forecasts of energy consumption for the next regulatory control period is shown in Figure 4.2 below.

CitiPower submits that these adjustments are appropriate. This is demonstrated by Frontier's Review of policy adjustments, June 2010.[120] CitiPower engaged Frontier to estimate the expected impact on energy consumption in the next regulatory control period of Government policies designed to address climate

[117] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p28.

[118] Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010 (provided to the AER by email on 28 April 2010), p7.

[119] NIEIR, Electricity sales and customer numbers for the Citipower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p9.

[120] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal),

change and energy efficiency. Frontier's conclusions regarding the appropriate level of post model adjustments is also set out in Figure 4.2 below.

Figure 4.2 shows that the overall level of post model adjustments to energy consumption estimated by NIEIR (in its June 2010 report) and the level estimated by Frontier are consistent. Given this represents the views of two independent experts, CitiPower submits that, on the evidence before it, the AER should be satisfied as to the appropriateness of NIEIR's overall level of post model adjustments to its energy consumption forecasts.

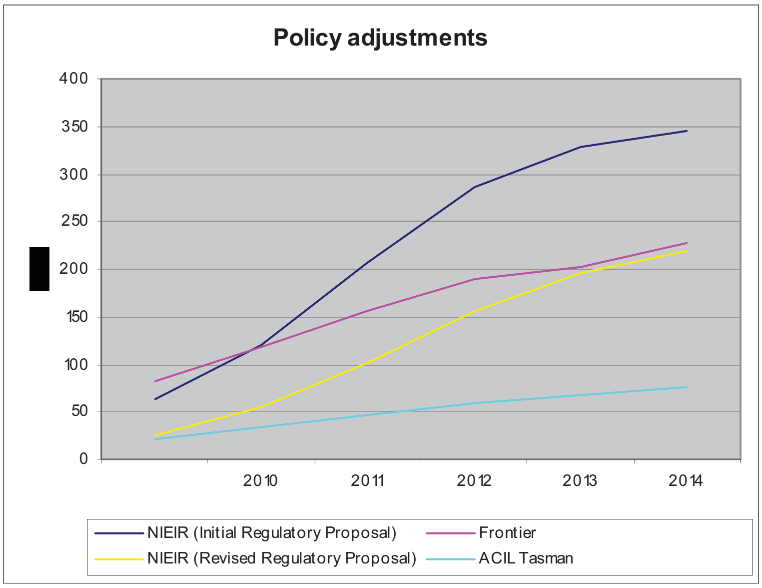

Figure 4.2 Forecast post model adjustments by NIEIR, Frontier and ACIL Tasman

CitiPower notes that, while the AER may raise concerns in respect of particular post model adjustments made by NIEIR, it must exercise caution in making reductions to one or other NIEIR adjustment without considering the implications for the other adjustments. This is because, as noted by Frontier, any determination of post model adjustments involves taking into account potential double counting due to policy overlap, and thus the adjustments determined by any given expert are generally interdependent rather than standalone.[121]

The AER's own consultant, ACIL Tasman, recognised the importance of policy overlap in reviewing post model adjustments and noted NIEIR's efforts to address this.[122]

Accordingly, where the AER is satisfied that the overall quantum of NIEIR's post model adjustments is appropriate, it would be erroneous for the AER to make reductions to individual NIEIR adjustments. Further, in the event that the AER does make a reduction to an individual NIEIR post model adjustment for the impact on energy consumption of a specific policy measure, it would be erroneous to disregard any offsetting effects on the overall level of the post model adjustments. Specifically, there may be increases in the post model adjustments

[121] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), pix.
[122] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, Final report, 21 April 2010, p37.

for other policy measures, to reflect the removal of the potential for double counting that was recognised by the forecaster.

Nonetheless, to assist the AER in its assessment of this Revised Regulatory Proposal, CitiPower addresses below the reasons put forward by ACIL Tasman and the AER for rejecting the specific post model adjustments for the insulation rebate, one watt standby target, lighting MEPS and AMI roll-out.

Insulation rebate program

While NIEIR's forecasts of the impact of the Federal Government's insulation program have been reduced in light of the cancellation of the scheme, NIEIR's updated forecasts continue to reflect some impact of the scheme. For the reasons outlined below, CitiPower submits this is appropriate.

As noted by Frontier, given the rapid take-up of insulation prior to the cancellation of the program, the Government's discontinuation of the program does not necessarily mean that the potential energy savings from it should be entirely discounted.[123] Frontier found that Insurance Council of Australia and New Zealand data suggested a 28 per cent take-up rate of uninsulated homes in Victoria prior to the cancellation of the scheme.[124] Frontier considered that this, together with more recent evidence which indicates that total claims were 1.1 million of an estimated total of 2.7 million uninsulated homes[125] by the time of the cancellation of the program, justifies an adjustment to take into account some impact on energy consumption from the program.[126]

Despite the cancellation of the insulation rebate program, therefore, it is appropriate to take into account the impact of the program on energy consumption in the next regulatory control period. Given the consistency between the overall level of post model adjustments made by NIEIR (and adopted by CitiPower) and the overall level of post model adjustments estimated by Frontier, the AER should also be satisfied that the post model adjustment to energy consumption forecasts for the insulation program proposed by CitiPower is appropriate.

As foreshadowed above, in the event the AER does seek to remove or alter NIEIR's post model adjustment for the insulation rebate, the AER must consider any impact this has for other policy adjustments. For example, NIEIR discounts the forecast impact of VEET on energy consumption on the basis of the policy's overlap with other Federal and Victorian Government initiatives, including the insulation rebate program.[127]

[123] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), pp62-3.

[124] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), pp62-3; Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p8.

[125] Hawke, A, Hawke Report, Review of the Administration of the Home Insulation Program, 6 April 2010 (Attachment 57 to this Revised Regulatory Proposal), p24.

[126] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), pp62-3; Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p8; Minister Assisting the Minister for Climate Change and Energy Efficiency, Media release re Home Insulation Safety Plan, 1 April 2010 (Attachment 54 to this Revised Regulatory Proposal).

[127] NIER, Electricity sales and customer number projections for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p67; Frontier, Review of policy adjustments, June 2010 (Attachment 36 to this Revised Regulatory Proposal), pp55-6.

One watt standby target

Contrary to ACIL Tasman's recommendation (with which the AER agreed), Frontier concluded that it is reasonable to take into account the impact of a one watt target for standby power.[128] Frontier reached its conclusion as follows:[129]

- In 2000, all Australian jurisdictions (through the MCE) endorsed the International Energy Agency's one watt program for standby power.[130]
- The MCE's strategy involved a two stage process:[131]
    - Stage 1 – for all key products, develop a product profile which outlines standby power performance and targets.
    - Stage 2 – where voluntary action under stage 1 is inadequate and/or where the MCE accepts that regulation is necessary to achieve the standby target, introduce mandatory standby performance measures.

Accordingly, the presence of mandatory 'Stage 2' measures indicates that the achievement of the one watt standby target will occur in the future.

In responding to ACIL Tasman's findings, Frontier noted that a number of product profiles had been released, each containing a four watt voluntary target and a proposed mandatory one watt target for 2012.[132] In addition, CitiPower notes that recent statements by the Government suggest that the MCE remains committed to reducing standby energy consumption. Both the *Equipment Energy Efficiency Program Achievements 2008/09* report and the *Consultation Regulation Impact Statement: National Legislation for Appliance and Equipment Minimum Energy Performance Standards (MEPS) and Energy Labelling* indicate that all home and office electrical appliances not already subject to energy efficiency regulation will be subject to a uniform one watt standard to be introduced in April 2013.[133]

Regarding ACIL Tasman and the AER's assertion that the adjustment for a one watt standby target should be removed because one watt standby targets are already reflected in NIEIR's baseline energy consumption forecasts, CitiPower

[128] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p49.

[129] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p49.

[130] MCE, Money Isn't All You're Saving, Australia's standby power strategy 2002-2012, 2002 (Attachment 38 to this Revised Regulatory Proposal).

[131] MCE, Money Isn't All You're Saving, Australia's standby power strategy 2002-2012, 2002 (Attachment 38 to this Revised Regulatory Proposal), pp10-1.

[132] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p9.

[133] Equipment Energy Efficiency Program, Achievements 2008/09, December 2009 (Attachment 39 to this Revised Regulatory Proposal), p15; Department of the Environment, Water, Heritage and the Arts, Consultation Regulation Impact Statement: National Legislation for Appliance and Equipment Minimum Energy Performance Standards (MEPS) and Energy Labelling, January 2010 (Attachment 40 to this Revised Regulatory Proposal), p81.

observes that NIEIR has recognised existing standby targets in preparing its energy consumption forecasts.[134]

Similarly, in preparing its forecast of the impact, Frontier excluded the contribution to energy savings of air conditioners and televisions.[135] It did so because these appliances are already subject to MEPS.[136]

Thus, on the basis of the evidentiary material before it, the AER should be satisfied that a post model adjustment to account for the impact on energy consumption of a one watt standby target in the next regulatory control period is appropriate. As noted above, the consistency in the overall level of post model adjustments forecast by independent experts NIEIR and Frontier suggests that the quantum of the post model adjustment for the one watt standby target proposed by CitiPower is appropriate.

Lighting MEPS

Frontier rejects ACIL Tasman's analysis of NIEIR's post model adjustment for lighting MEPS.

First, after reviewing a wider range of material than the Lighting RIS, Frontier finds that the Lighting RIS may underestimate the level of residential lighting use (and savings).[137]

Second, Frontier notes that ACIL Tasman considered only the estimate for residential lighting set out in the Lighting RIS and ignores the Lighting RIS' estimate for commercial lighting.[138] Frontier notes that this is inconsistent and goes on to find that the Lighting RIS contemplates considerably higher savings in commercial lighting energy than NIEIR. The result of this is that ACIL Tasman significantly underestimates the impact of lighting MEPS on energy consumption. Accordingly, Frontier concludes that ACIL Tasman's analysis, which considers only residential savings, should be rejected.[139]

As noted above, the consistent forecasts of the total level of post model adjustments estimated by NIEIR and Frontier indicate that the post model adjustment put forward by CitiPower for lighting MEPS in this Revised Regulatory Proposal is appropriate.

[134] NIEIR, Electricity sales and customer number projections for the CitiPower region to 2019, November 2009 (Attachment C0005 to the Initial Regulatory Proposal), p53; NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34] to this Revised Regulatory Proposal), p61.

[135] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p52.

[136] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p52.

[137] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), pp9-11; Frontier, Review of policy adjustments, June 2010 (Attachment 36 to this Revised Regulatory Proposal), pp34-6.

[138] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p11.

[139] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), pp11-2.

However, should the AER seek to constrain the lighting MEPS post model adjustment to the Lighting RIS, for the reasons identified by Frontier, the AER cannot rely on ACIL Tasman's analysis. The AER must also take into account the understatement of potential savings from residential lighting in the Lighting RIS and the estimated impact in the Lighting RIS of savings from commercial lighting.

CitiPower also notes that if the AER seeks to make any changes to NIEIR's post model adjustment for MEPS lighting, the AER would also be required to consider the impact this has on the quantum of NIEIR's policy adjustments for other interrelated policies. For example, as ACIL Tasman recognised, the impact of lighting MEPS was taken into account by NIEIR in forecasting the likely impact of VEET.[140] If the AER reduces the impact of lighting MEPS, the AER must consider the implications of this for the VEET adjustment.

AMI roll-out and TOU Tariffs

CitiPower submits that it is reasonable to assume that the AMI roll-out, or more specifically, the TOU Tariffs made possible by AMI, will have an impact on energy consumption in the next regulatory control period.

ACIL Tasman does not identify a provision of the Rules under which the AER could make any necessary adjustments at a future date to account for TOU Tariffs of the kind ACIL Tasman proposed. CitiPower is not aware of any relevant provisions that would allow for this and considers that, accordingly, the likely impact of the TOU Tariffs must be taken into account in the Final Determination in determining the appropriate forecasts of energy consumption.

As noted above, the AER rejected adjustments to energy consumption for the AMI roll-out and TOU Tariffs given:[141]

- the inconsistent approach adopted by NIEIR with respect to determining the impact of AMI on energy consumption and maximum demand forecasts;
- the uncertainty around the introduction of TOU tariffs; and
- impediments to the implementation of AMI and TOU tariffs.

CitiPower rejects the AER's assertion that NIEIR was inconsistent in its treatment of the impact of the AMI roll-out and TOU Tariffs on energy consumption and maximum demand.[142] While the AER indicated that '*at the very least an examination of the available literature, consistent with NIEIR's … approach for energy consumption, would be a reasonable approach to take'*,[143] as noted by the AER's consultant ACIL Tasman, and the AER itself, the research into the impact of TOU Tariffs has focussed on the impact on energy consumption, and not maximum demand.[144] Further, in response to the AER's comment that NIEIR did not consider certain papers discussed in the primary report relied on by NIEIR

[140] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p37.
[141] AER, Draft Determination, pp148-55.
[142] AER, Draft Determination, pp148-9.
[143] AER, Draft Determination, p149.
[144] ACIL Tasman, Review of maximum demand forecasts, 19 April 2010, p40; AER, Draft Determination, p149.

(the Brattle Group study),[145] CitiPower notes that this study is a survey of recent experiments.[146] That is, NIEIR relied on this report rather than conducting its own assessment of each of the underlying surveys. CitiPower submits this is entirely appropriate.

Regarding the uncertainty around the introduction of TOU Tariffs, CitiPower notes that it has agreed to a moratorium on TOU Tariffs only until the end of 2010. As evidenced by the letter from the Minister for Energy and Resources regarding his request for a deferral of TOU Tariffs, the Minister only requested that the introduction be deferred until 2011.[147]

CitiPower intends to move to TOU Tariffs in the next regulatory control period. This can be seen from CitiPower's presentation to retailers on 13 July 2010, which contemplates introduction of TOU Tariffs in January 2011.[148]

[redacted]

CitiPower notes that NIEIR assumes that TOU Tariffs will be introduced in 2013.[151] This is a conservative estimate of the likely timing of the TOU Tariffs given the moratorium has only been agreed to until the end of 2010.

In any event, as noted by Frontier, the moratorium does not prevent the introduction of optional TOU Tariffs.[152] Frontier concludes, based on its review

[145] AER, Draft Determination, p149.
[146] NIEIR, Maximum summer demand forecasts for CitiPower to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), p53; Faruqui, A and Sergici, S (Brattle Group), Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence, 10 January 2009 (Attachment 41 to this Revised Regulatory Proposal), p2.
[147] Minister for Energy and Resources, Letter re Deferral of Network Time of Use Tariffs, 24 February 2010 (Attachment 44 to this Revised Regulatory Proposal), p1.
[148] CitiPower and Powercor Australia, Presentation to the AMI retailers forum, Network Tariffs, Considered tariffs for 2011-15 price review period, 13 July 2010 (Attachment 45 to this Revised Regulatory Proposal), slides 2, 3, 7.
[149] Oakley Greenwood, Review of AMI Benefits and Consolidation of AMI Costs and Benefits (Confidential Draft Report), May 2010 (Attachment 53 to this Revised Regulatory Proposal), pp14, 36-9.
[150] DPI, Presentation to AMI Policy Committee, 29 June 2010 (Attachment 55 to this Revised Regulatory Proposal), slides 2, 5-7.
[151] NIEIR, Energy consumption and customer numbers for the CitiPower region to 2019, June 2011, p72.
[152] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p4; Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p18.

of several studies, that even a partial take-up of TOU Tariffs should deliver most of the energy savings from such a pricing structure.[153]

Accordingly, even if TOU Tariffs are not made compulsory in the next regulatory control period, CitiPower considers its proposed introduction of voluntary TOU Tariffs will reduce energy consumption in 2011-15.

The 'impediments to the implementation of AMI and TOU' raised by ACIL Tasman and the AER included the following:

- the inability of DNSPs to send price signals to customers, including because of:
    - the proportion of the total bill that distribution charges make up;[154] and
    - retailers incentives: 1) to modify the pricing signals to customers to better reflect the costs of their own businesses; and 2) to homogenise retail tariffs even where customers are serviced by different DNSPs;[155]
- the inability of customers to respond to TOU tariffs due to their personal circumstances, particularly in the short term;[156]
- inelastic demand for electricity in the short run;[157]
- the 'fatigue' effect, which suggests that once the novelty of the TOU tariff has worn off and customers notice that the increases in their bills are not as dramatic as they feared they might be, customers' interest in reducing energy consumption wanes;[158]
- similarly, the relativity effect, which suggests that as new prices become 'normal' and therefore not relatively more expensive than the reference point provided by recent prices, consumption might be expected to return to higher levels;[159] and
- the rebound effect.[160]

[153] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p24.
[154] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp51-52.
[155] AER, Draft Determination, p151.
[156] AER, Draft Determination, p151; ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p54.
[157] AER, Draft Determination, p151; ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp48 and 54.
[158] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp48-9.
[159] AER, Draft Determination, pp151-2; ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, pp41-2. While the AER relies on ACIL Tasman's descriptions of the relativity and rebound effects that appear in its report on adjustment to maximum demand forecasts, these descriptions do not appear in ACIL Tasman's report on energy consumption. CitiPower nonetheless addresses these points in this Revised Regulatory Proposal as the AER appears to suggest they apply equally in respect of the impact of the AMI roll-out on energy consumption.
[160] AER, Draft Determination, pp151-2; ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p42.

CitiPower acknowledges that DNSPs' charges only constitute a part of the end price paid by consumers. However, CitiPower does not consider that this prevents DNSPs from sending price signals to consumers. CitiPower thus does not consider this to be a valid basis for reducing NIEIR's estimated impact of TOU tariffs in the next regulatory control period.

As noted by Frontier, the fact that distribution charges make up only part of the end price paid by consumers is consistent with the situation in the trials of advanced meters.[161] Thus, the results of the trials relied on by NIEIR and Frontier in estimating the impact of the AMI roll-out would already reflect this and the estimates based on these trials should not be adjusted to account for this.

CitiPower also notes that retailers have a commercial incentive to 'pass through' DNSP pricing structures to reduce the risk of under-recovery. While retailers are adept at managing pool price risk (i.e. the risk associated with energy prices), for example, through hedging contracts and generator ownership, retailers cannot so easily manage the risk associated with changing distribution charges. Given the small margins retailers generate, their approach to managing risk associated with distribution charges is to pass these charges onto consumers, rather than to bear the risk themselves.

CitiPower observes that the AER has not provided any evidence of retailers seeking to charge consumers consistent prices. To the contrary, CitiPower notes that retailers publish different tariffs, depending on the distribution region.[162]

CitiPower also does not agree with the AER's conclusion that, because certain consumers will not be in a position to respond to the price signals they receive, the expected impact of TOU Tariffs should be reduced. This rejection of the AER's reasoning follows from Frontier's finding that the bulk of any reduction in energy consumption from the implementation of TOU Tariffs will generally be driven by a minority of customers.[163] The fact that some customers may not be in a position to reduce energy consumption as a result of TOU Tariffs does not mean that other customers, who are in a position to respond, will not take up TOU Tariffs and reduce overall energy consumption.

Frontier notes that ACIL Tasman's statement that demand for electricity is inelastic in the short run is inconsistent with its reference to consumer 'fatigue' (which supposes that consumer response to TOU Tariffs is not sustained in the long run).[164] The same can be said in respect of ACIL Tasman's comments on the relativity and rebound effects.

Regarding the 'fatigue' effect, Frontier observes that ACIL Tasman only cites one example (being the California Statewide Pricing Pilot).[165] As noted by Frontier,

[161] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p5.
[162] See for example AGL Sales' and Origin Energy's standing offers (tariffs applicable from 1 January 2010) (Attachments 46 and 47 to this Revised Regulatory Proposal).
[163] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p24.
[164] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), pp5-6.
[165] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p6.

when Charles River Associates originally reported the results of this trial they discounted the value of the result due to the small sample sizes and other complexities and recommended using normal weekday elasticities from critical peak pricing results rather than the TOU results for determining the impact of TOU Tariffs.[166] The California Statewide Pricing Pilot is therefore not a strong basis for disregarding expected reductions in energy consumption.[167] ACIL Tasman also relies on the California Statewide Pricing Pilot to support its statements regarding the relativity effect.[168] Accordingly, CitiPower submits there is no evidence before the AER to support a conclusion that the impact on energy consumption from TOU Tariffs is likely to reduce over time as a result of the 'fatigue' or relativity effects.

In developing their forecasts of the impact of TOU Tariffs on energy consumption, both NIEIR and Frontier allow for the inelasticity of demand in the short-run by 'smoothing' the demand response and discounting the short-term energy savings.[169] If anything, as noted by Frontier, the inelasticity of demand for electricity in the short term may suggest that short-term trial results (which form the basis for TOU Tariff impact estimates) understate the potential savings from TOU Tariffs in the long run.[170] Thus, forecast impacts of TOU Tariffs on energy consumption based on these trials are likely to be conservative.

ACIL Tasman suggests that the 'rebound effect' means that, as time passes, consumers may become less responsive to TOU Tariffs.[171] ACIL Tasman indicates that this is because:[172]

- energy bills are a relatively small amount of disposable income;
- the people whose behaviour must change are not necessarily the payers of the bills; and
- the message may be lost over time.

The phenomenon of the 'rebound effect' is not consistent with ACIL Tasman's examples. The rebound (or take-back) effect is the notion that more efficient appliances mean that it is cheaper for a customer to obtain a given level of service, which may induce the customer to use that appliance more.[173] For example, efficient lighting might discourage consumers from turning off lights, given the cost of leaving them on is much lower than it previously was.[174] Given

[166] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p6.
[167] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p6.
[168] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p42.
[169] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p5.
[170] Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p5.
[171] AER, Draft Determination, pp151-152; ACIL Tasman, Review of maximum demand forecasts, 19 April 2010, p42.
[172] AER, Draft Determination, pp151-152; ACIL Tasman, Review of maximum demand forecasts, 19 April 2010, p42.
[173] Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010, p18.
[174] Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010, p18.

TOU Tariffs do not entail any increases in efficiency, the rebound effect is not relevant. The examples that ACIL Tasman provided are more consistent with the 'fatigue' or relativity effects discussed above. For the reasons outlined above, the evidence before the AER does not support a conclusion that the impact on energy consumption from TOU Tariffs is likely to reduce over time as a result of these effects.

In any event, CitiPower notes that NIEIR considered its estimates of the impact of TOU Tariffs are conservative. Based on five key Australian and overseas studies, NIEIR formed the view that the average overall percentage reduction in energy consumption due to TOU Tariffs is eight per cent.[175] However, the percentage reduction assumed by NIEIR to arise in the next regulatory control period due to TOU Tariffs for the purposes of forecasting energy consumption was four per cent.[176]

The AER noted that NIEIR did not assume price signals would be delivered to customers through the use of IHDs, and did not assume any other enabling technologies, with the result that the only mechanism by which price signals can be taken into account is through retail billing arrangements.[177] However, as noted by Frontier, the minimum Victorian AMI roll-out requires that all AMI meters have an interface to a home area network, which will facilitate IHDs.[178] Frontier considered therefore that it was reasonable to assume that some benefits of IHDs could potentially be realised.[179]

Finally, CitiPower observes that, even if the AER does not accept that TOU Tariffs will reduce energy consumption in the next regulatory control period, there are emerging technologies with effects on energy consumption similar to TOU Tariffs (that have not been taken into account by NIEIR) that the AER should consider. For example, Google PowerMeter is a free energy monitoring tool that uses energy information provided either by smart meters or energy monitoring devices.[180] It allows users to view their energy consumption from anywhere online.[181] Google PowerMeter:[182]

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[175] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p71.

[176] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p72.

[177] AER, Draft Determination, p151.

[178] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p23.

[179] Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p23.

[180] Google is partnered with 'Current Cost': Become a Google PowerMeter partner, available at http://www.google.com/powermeter/about/partnerships.html (Attachment 59 to this Revised Regulatory Proposal). In Australia, Current Cost energy monitoring devices (called ENVI) can be purchased from the 'SmartNow' website (http://www.smartnow.com.au/current_cost_google_powermeter.html). ENVI, together with the necessary cables and or adaptors be purchased for around $210.00: SmartNow and Current Cost ENVI, available at http://www.smartnow.com.au/current_cost_envi_store.php. For information regarding ENVI, see the CC128 ENVI Manual (Attachment 60 to this Revised Regulatory Proposal).

[181] What is Google PowerMeter, available at http://www.google.com/powermeter/about/about.html (Attachment 58 to this Revised Regulatory Proposal).

[182] What is Google PowerMeter, available at http://www.google.com/powermeter/about/about.html (Attachment 58 to this Revised Regulatory Proposal).

- provides information regarding the amount of energy used by day, week or month;
- provides information in respect of the amount of power used by appliances that are always on;
- allows users to make comparisons to data belonging to other users;
- predicts a user's annual energy bill; and
- allows users to establish savings goals and track the progress of those goals.

Google PowerMeter therefore presents a free option for consumers to monitor and reduce their energy consumption. Such technology will reduce energy consumption in the next regulatory control period, regardless of whether TOU Tariffs are introduced.

Given the above, CitiPower considers that the AER should be satisfied on the material before it that a post model adjustment to account for the impact of TOU Tariffs on energy consumption is appropriate. Further, as previously noted, the consistency of the overall post model adjustments estimated by NIEIR and those of Frontier indicate that the AER should be satisfied as to the level of the adjustment for the AMI roll-out and TOU Tariffs proposed by CitiPower in this Revised Regulatory Proposal.

4.3.3.5 Alternative energy consumption forecasts

In the event the AER seeks to adjust CitiPower's forecasts for energy consumption in the next regulatory control period, neither VENCorp's nor ACIL Tasman's forecasts can be relied on to forecast energy consumption in the next regulatory control period.

VENCorp's forecasts

The AER noted in its Draft Determination that the Victorian DNSPs' forecasts of energy consumption differ significantly from those published in VENCorp's 2009 Victorian Annual Planning Report 2009, 16 July 2009.[183]

However, VENCorp's forecasts are now significantly out of date and do not reflect recent economic conditions. Further, CitiPower notes that methodological difficulties would likely arise in splitting VENCorp's state wide forecasts across the Victorian DNSPs' distribution areas.

ACIL Tasman's forecasts

The forecasts of energy consumption used by the AER in its Draft Determination are not realistic or appropriate. Considering the data for 2001-05 and 2006-10, Table 4.1 shows that there is a significant jump in the CAGR predicted by ACIL Tasman away from historic levels. That is, the AER is forecasting energy consumption well in excess of the long term average. This is not reasonable,

[183] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p8.

particularly given the current climate in which a number of Government policies are directed at reducing energy consumption.

	GWh					CAGR
	2006	2007	2008	2009	2010	2006-09
Draft Determination	5,975	6,079	6,100	6,041	6,105	0.36%
Revised Regulatory Proposal	5,975	6,079	6,100	6,096	6,125	0.67%
	2011	2012	2013	2014	2015	2010-15
Draft Determination	6,246	6,430	6,544	6,595	6,678	1.81%
Revised Regulatory Proposal	6,177	6,210	6,182	6,148	6,177	0.17%

Table 4.1 CAGR comparison between the current and forthcoming regulatory control periods

4.3.4 CitiPower's Revised Regulatory Proposal

The energy consumption forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 4.2 below.

	2011	2012	2013	2014	2015
Energy consumption (GWh)	6,177	6,210	6,182	6,148	6,177

Table 4.2 Energy consumption forecasts in the Revised Regulatory Proposal

4.4 Maximum demand forecasts

4.4.1 CitiPower's Initial Regulatory Proposal

The methodology for the spatial maximum demand forecasts underpinning CitiPower's Initial Regulatory Proposal was set out in correspondence to the AER dated 22 December 2009.

In its review of CitiPower's policies, practices, procedures and governance arrangements, the independent expert, PB concluded that CitiPower's approach to forecasting demand is appropriate and reasonable given the relatively low growth of network demand.[184] CitiPower used the same approach to forecasting maximum demand in preparing its Initial Regulatory Proposal as is evident in the policies, practices, procedures and governance arrangements reviewed by PB.

CitiPower also submitted with its Initial Regulatory proposal system level maximum demand forecasts prepared by NIEIR.[185] However, as noted in material provided by CitiPower to the AER subsequent to the Initial Regulatory Proposal, CitiPower did not compare NIEIR's forecasts with its own internal spatial

[184] PB, Review of CitiPower's policies, practices, procedures and governance arrangements, October 2009 (Attachment C0042 to CitiPower's Initial Regulatory Proposal), pp7-9 and 11.
[185] NIEIR, Maximum demand forecasts for CitiPower terminal stations to 2019, November 2009 (Attachment P006 to the Initial Regulatory Proposal).

maximum demand forecasts.[186] Given this, CitiPower did not seek to identify errors in the report submitted.

4.4.2 AER's Draft Determination

The main flaw identified by the AER in the Victorian DNSPs' methodology for forecasting maximum demand was a lack of appropriate reconciliation to NIEIR's top down forecasts.[187] The AER considered such a top down reconciliation to be fundamental to producing reasonable spatial demand forecasts.[188]

While acknowledging actual maximum demand in 2006-08 may have been affected by the onset of the GFC, the AER indicated that, on average, CitiPower's forecasts exceeded actual maximum demand by 19 per cent over 2006-08.[189]

The AER rejected CitiPower's proposed maximum demand forecasts and substituted the maximum demand forecasts recommended by ACIL Tasman.[190]

The reasoning underlying the AER's Draft Determination is discussed in more detail below.

4.4.3 CitiPower's response to the AER's Draft Determination

CitiPower does not accept the AER's forecasts of maximum demand, substituted in the AER's Draft Determination for those in its Initial Regulatory Proposal. CitiPower responds to the AER's concerns regarding its maximum demand forecasts in its Initial Regulatory Proposal by:

- explaining why, contrary to the AER's analysis, CitiPower's internal spatial demand forecasts have been demonstrated historically to have a high degree of accuracy;
- updating its own internal spatial maximum demand forecasts to reflect lower than expected maximum demand in 2009-10 in four zone substations;
- providing revised NIEIR forecasts of system maximum demand that are updated for currency and reflect corrections to the data underpinning NIEIR's November 2009 forecasts (provided with CitiPower's Initial Regulatory Proposal); and
- reconciling CitiPower's updated internal spatial maximum demand forecasts with these revised NIEIR forecasts of system maximum demand. As CitiPower's updated internal spatial maximum demand forecasts are consistent with NIEIR's revised forecasts, CitiPower has not made any adjustments to its internal spatial maximum demand forecasts in this Revised Regulatory Proposal.

[186] CitiPower, Maximum Demand forecasting – Questions for CitiPower (CP), Responses requested by 12 February 2009 (provided to the AER by email on 19 February 2010), p6.

[187] AER, Draft Determination, p92.

[188] AER, Draft Determination, pp122 and 133.

[189] AER, Draft Determination, p81 (Table 5.7).

[190] AER, Draft Determination, pp132-3 and 155-6.

4.4.3.1 Spatial maximum demand forecasts

CitiPower rejects the AER's suggestion that their spatial demand forecasts are likely to overstate maximum demand in 2011-15.

As recognised by the AER, it is the non-coincident maximum demand forecasts at particular points in the network that are the main driver for growth driven capex.[191]

CitiPower notes that the AER erred in its calculation of the difference between forecast and actual maximum demand.[192] The peak demand forecasts relied on by the AER for the purposes of its analysis were incorrectly cited by the ESCV as being non-coincident zone substation level forecasts.[193] The forecasts included in the ESCV's 2006-10 EDPR were in fact the sum of the feeder peak demands CitiPower submitted to the ESCV.[194] The AER compared the sum of these feeder demand forecasts to the actual unadjusted maximum demand at the network level. In short, the AER compared 'apples with oranges'.

In making a comparison between actual system maximum demand and the forecast sum of feeder maximum demands, it is to be expected there will be a reasonably large difference. This is because:

- the distribution feeders from a zone substation will not all peak at the same time and thus the sum of their maximum demands will always be greater than the sum of the maximum demand of the zone substation; and
- the zone substations will also not peak at the same time, hence the sum of their maximum demands will always be greater than the maximum demand of the network.

The AER has not considered the significant diversity between feeder maximum demands and the system maximum demand.

Contrary to the AER's suggestion in its Draft Determination, CitiPower's forecasts for 2006-08 zone substation maximum demand were consistent with the actual level over the period. As shown in Table 4.3 below, the actual maximum demand in CitiPower's zone substations in the period 2006-10 was, on average, 97.6 per cent of its forecast.]

[191] AER, Draft Determination, p74.
[192] AER, Draft Determination, p81 (Table 5.7). Details of the calculation were provided to CitiPower by the AER by email on 16 June 2010.
[193] The AER indicated in an email from Lawrence Irlam to CitiPower on 16 June 2010 that it relied on the forecasts 'from the ESCV's determination (table 4.3 on page 133 of its determination)'.
[194] Templates 10(b) to 10(e) submitted to the ESCV in the 2006-10 EDPR process by CitiPower, 13 November 2004 (Attachment 48 to this Revised Regulatory Proposal) show that the figures cited by the ESCV on p133 of its EDPR 2006-10 (Volume 1) (Attachment 31 to this Revised Regulatory Proposal) are the sum of the peak demand on each feeder.

Total ZSS maximum demand (MW, 50%PoE)	2006	2007	2008	2009	2010
Forecast[195]	1386	1418	1463	1494	1524
Actual (weather adjusted)[196]	1354	1403	1466	1431	1455
Actual relative to forecast	97.7%	98.9%	100.2%	95.8%	95.4%

Table 4.3 CitiPower's zone substation maximum demand forecasts relative to actual maximum demand

Far from suggesting that CitiPower's methodology for forecasting spatial maximum demand is unreliable, a proper comparison of CitiPower's forecasts of maximum demand for 2006-08 and actual maximum demand demonstrates the accuracy and reliability of CitiPower's forecasting methodology.

Further, CitiPower's 2010 actual maximum demand figures are consistent with the maximum demand forecasts included in the Initial Regulatory Proposal. CitiPower's total forecast zone substation maximum demand was 1524 MW in 2010, while actual maximum demand was 1455 MW (95 per cent of the forecast).[197] The difference between forecast and actual maximum demand in 2010 was driven by four zone substations in the industrial precinct of Fisherman's Bend (CitiPower's weather normalised non-coincident maximum demand forecasts at the zone substation level other than these zone substations were very consistent with the 50 per cent PoE forecasts). Given the zone substation maximum demands experienced in 2009-10 were lower than anticipated, CitiPower has updated its spatial maximum demand forecasts for the next regulatory control period in these four zone substations. CitiPower's updated forecasts for these zone substations, and the sum of its zone substation maximum demand forecasts, are set out in Table 4.4 below.

		2011	2012	2013	2014	2015
Total						
Sum of zone substation maximum demand forecasts		1517	1559	1627	1669	1711
Difference from Initial Regulatory Proposal (MW)		22	22	22	22	23
Difference (%)		1.4%	1.4%	1.3%	1.3%	1.3%
Targeted zone substations						
E	Initial Regulatory Proposal	8.1	8.2	8.4	8.5	8.6
	Revised Regulatory Proposal	7.2	7.3	7.4	7.5	7.6

[195] Templates 10(b) to 10(f) submitted to the ESCV in the 2006-10 EDPR process by CitiPower, 13 November 2004 (Attachment 48 to this Revised Regulatory Proposal).

[196] See Revised Regulatory Template 6.3.

[197] Revised Regulatory Template 6.3 (Tables 11 and 21). CitiPower observes that actual 2010 maximum demand data is now available. Accordingly, actual summer 2009-10 maximum demand data has been used to complete the '2010' column in Revised Regulatory Template 6.3 Tables 17 and 21 (despite the fact the heading of this column is 'Estimate').

FB	Initial Regulatory Proposal	33.0	33.9	34.7	35.5	36.6
	Revised Regulatory Proposal	24.2	25.0	25.7	26.5	27.6
MG	Initial Regulatory Proposal	45.4	47.6	50.0	52.3	54.5
	Revised Regulatory Proposal	38.7	41.0	43.1	45.3	47.5
WG	Initial Regulatory Proposal	38.5	41.9	45.6	49.1	53.6
	Revised Regulatory Proposal	32.8	36.7	40.1	43.6	48.0

Table 4.4 Revisions to non-coincident zone substation maximum demand forecasts (MW) from CitiPower's Initial to Revised Regulatory Proposal

CitiPower does not consider that ACIL Tasman's forecasts of maximum demand are an appropriate substitute for CitiPower's forecasts. ACIL Tasman placed undue reliance on the November 2009 NIEIR maximum demand forecasts for 2011-15, which as noted above, CitiPower did not review for data accuracy. As discussed in more detail below, NIEIR's November 2009 maximum demand forecasts are not reliable.

CitiPower also notes that, while it has provided historical figures for zone substation coincident maximum demand in Revised Regulatory Template 6.3, the AER should exercise caution in using these figures for any trend analysis. The independent expert engaged by CitiPower, SKM, concluded that raw coincidence factors **cannot** be used as a reliable estimate for either individual non-coincident zone substation maximum demands or summated zone substation non-coincident maximum demand for 2011-15.[198]

4.4.3.2 Top down reconciliation

The AER's top down reconciliation of CitiPower's forecast maximum demand forecasts with NIEIR's maximum demand forecasts does not result in realistic forecasts of maximum demand. This is because the reconciliation was conducted using NIEIR's maximum demand forecasts of November 2009, which were based on data containing errors and data which is no longer current.

In responding to the concerns raised by the AER, however, CitiPower has conducted a top-down reconciliation of its internal spatial demand forecasts with NIEIR's updated system maximum demand forecasts. This reconciliation showed that CitiPower's internal spatial demand forecasts are consistent with NIEIR's system maximum demand forecasts.

NIEIR's maximum demand forecasts

As noted above, NIEIR's most recent system level maximum demand forecasts for the next regulatory control period are attached to this Revised Regulatory

[198] SKM, CitiPower/Powercor Demand Forecasts, 8 July 2010 (Attachment 50 to this Revised Regulatory Proposal), pp26 and 28.

Proposal.[199] CitiPower submits that NIEIR's updated demand forecasts are reasonable because they:

- are based on data corrected for errors in the data underpinning the original forecasts;
- were prepared using a reasonable methodology; and
- are based on reasonable input assumptions.

The data underpinning NIEIR's original forecasts was incomplete as it did not reflect the following:

- net HV feeder cross boundary supply from other DNSPs; and
- additional co-generators on CitiPower's system.

The impact of this additional data provided to NIEIR (and the impact they had on NIEIR's recorded maximum demand for 2009) are set out in Table 4.5 below.

	MW
NIEIR November 2009 recorded system maximum demand	1433
Net HV feeder cross boundary supply from other DNSPs	37
Additional NIEIR estimate for co-generation on CitiPower's system	8
Updated NIEIR CitiPower 2009 recorded system maximum demand	1462

Table 4.5 Impact of corrected data on NIEIR's recorded maximum demand

Regarding NIEIR's methodology, the AER's own consultant, ACIL Tasman, concluded that NIEIR's approach to forecasting maximum demand includes a number of features that are necessary and desirable in any maximum demand forecasting process and is generally sound.[200] As a result, ACIL Tasman did not recommend the use of an alternative model. In addition, given NIEIR's demand forecasting methodology relies on many of the same models as are used in the energy consumption forecasting process, CitiPower observes that many of Frontier's positive findings regarding NIEIR's energy consumption forecasting methodology also apply equally to NIEIR's maximum demand forecasting methodology.[201]

The AER therefore has sufficient material before it to conclude that NIEIR's maximum demand forecasting methodology is reasonable and should be so satisfied on the basis of that material.

[199] NIEIR, Maximum summer demand forecasts for CitiPower to 2010, June 2010 (Attachment 43 to this Revised Regulatory Proposal).
[200] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p19.
[201] These findings are set out in Frontier's report, Review of NIEIR's methodology for forecasting electricity consumption, April 2010, provided to the AER on 28 April 2010. As CitiPower did not rely on NIEIR's forecasts of maximum demand in preparing its Initial Regulatory Proposal, CitiPower did not engage Frontier to prepare a similar report in respect of NIEIR's maximum demand forecasting methodology.

Given the consistency between the input assumptions made by NIEIR in forecasting energy consumption and maximum demand, the concerns of ACIL Tasman and the AER relating to NIEIR's population and economic growth assumptions in the energy consumption context also arose in the context of maximum demand. As noted above in respect of NIEIR's energy consumption forecasts NIEIR's updated forecasts address these concerns as follows:

- NIEIR assumes average population growth of 1.4 per cent across Victoria in the next regulatory control period,[202] which is consistent with the ABS' 'series B' population forecast that ACIL Tasman recommended; and
- NIEIR's updated economic growth forecasts reflect recent economic conditions.[203]

Similarly, while, as noted above, the AER raised concerns regarding NIEIR's assumptions in respect of the CPRS, NIEIR's revised maximum demand forecasts assume that the CPRS will be delayed to 1 January 2013.[204]

ACIL Tasman and the AER also expressed concerns in respect of the post model adjustments made by NIEIR to its maximum demand forecasts for three policies:[205]

- the insulation rebate program;
- the one watt standby target; and
- the AMI roll-out.

CitiPower considers that each of these adjustments reflected in NIEIR's revised forecasts are reasonable.[206] This is because, as noted above in respect of the post model adjustments to energy consumption forecasts:

- Frontier has demonstrated that, despite the cancellation of the insulation rebate program, the take up of insulation prior to the cancellation indicates that some impact should be taken into account. NIEIR's updated maximum demand forecasts reflect the Federal Government's discontinuation of the scheme.
- It is realistic to assume a one watt standby target will arise in the next regulatory control period, and it is appropriate to make an adjustment to forecasts to account for this (provided the impact of existing policies is

[202] NIEIR, Maximum summer demand forecasts for CitiPower to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), p21.
[203] NIEIR, Maximum summer demand forecasts for CitiPower to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), pp2-27.
[204] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p9.
[205] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, pp30-33, 39-44; AER, Draft Determination, pp120-1, and 147-55.
[206] CitiPower observes that it did not seek a report from Frontier regarding the quantum of NIEIR's policy adjustments to its maximum demand forecasts because it did not rely on NIEIR's forecasts in preparing its Initial Regulatory Proposal.

accounted for). NIEIR has recognised existing standby targets in preparing its maximum demand forecasts.[207]

- It is reasonable to assume that TOU Tariffs will be introduced by CitiPower in the next regulatory control period, and NIEIR's assumption that TOU Tariffs will be introduced in 2013 is a conservative estimate of the likely timing of the Tariffs.[208] Further, the 'impediments to the implementation of AMI and TOU' raised by ACIL Tasman and the AER are not borne out in the evidence presented. Finally, for the reasons outlined above, CitiPower rejects the AER's assertion that NIEIR was inconsistent in its assessment of the impact of TOU Tariffs on energy consumption and maximum demand.

CitiPower notes that it is realistic to expect the impact on maximum demand forecasts from TOU Tariffs to be smaller than the impact on energy consumption. CitiPower's TOU Tariffs would likely spread the peak period across five or six hours.[209] The reduction in maximum demand as a result of TOU Tariffs spread over several hours would be minimal. Peak demand energy consumption is typically more responsive to pricing structures involving critical peak pricing. CitiPower is not proposing such a structure.

In addition, the AER's findings in respect of the impact of weather on maximum demand are incorrect. In its Draft Determination, the AER stated the following:[210]

> '*While the AER is cognisant that maximum demand may be more sensitive to temperature rather than TOU, weather impacts are typically in the context of a 50 PoE temperature (approximately an average of 29 degrees). Contrary to NIEIR's assumption that customers would (largely) ignore prices at such temperatures and activate air conditioning as per normal, a more plausible outcome is that, in light o the education around TOU tariffs, customers would choose to adjust the thermostat on their air conditioners to a higher temperature (for example, 23 degrees instead of 21 degrees Celsius) and this is likely to result in a reduction in maximum demand.*'

The AER does not provide any basis for its conclusions. CitiPower considers that, in circumstances where consumers have invested in installing an air conditioning unit, the additional cost associated with running the air conditioner in peak periods on days where the temperature is at or above 29 degrees is relative insignificant. Consumers are therefore likely to continue to use air conditioners at these times, indeed, they are particularly likely to use air conditioners at these

[207] NIEIR, Maximum summer demand forecasts for CitiPower to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), p44.
[208] NIEIR, Maximum summer demand forecasts for CitiPower to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), p55.
[209] CitiPower and Powercor Australia, Presentation to AMI retailers forum, Network Tariffs, Considered tariffs for 2011-15 price review period, 13 July 2010 (Attachment 45 to this Revised Regulatory Proposal), slides 2, 3 and 7.
[210] AER, Draft Determination, p149.

times. Therefore, regardless of whether the peak tariff periods coincide with peak demand periods, TOU Tariffs are unlikely to have an impact on maximum demand because maximum demand is more sensitive to weather than TOU Tariffs. CitiPower also observes that the AER has not presented any evidence that peak demand would be reduced as a result of consumers switching air conditioners from 21 degrees to 23 degrees and it is not clear that this would be the result.

For the reasons outlined above, any reconciliation of its spatial demand forecasts should be with NIEIR's updated maximum demand forecasts.

Methodology for reconciliation

The method adopted by CitiPower to reconcile its maximum spatial demand forecasts with the updated NIEIR system maximum demand forecasts is as follows:

1. By reference to SKM's expert report on CitiPower's maximum demand forecasts, CitiPower / Powercor Demand Forecasts, 8 July 2010, confirm if a reasonably reliable ratio can be established between the 50 per cent PoE historical non-coincident zone substation maximum demands and Citipower's network maximum demand.
2. Compare the 2011-15 zone substation non-coincident 50 per cent PoE maximum demand forecasts (Revised Regulatory Template 6.3, Table 21) with the NIEIR's 50 per cent PoE system maximum demand forecasts (Revised Regulatory Template 6.3, Table 12).
3. Test if the ratio observed in step 2 is within the 90 per cent confidence level of the ratio set out by SKM in its report CitiPower / Powercor Demand Forecasts, 8 July 2010.
4. If ratio is significantly outside the 90 per cent confidence level set out by SKM, revise the spatial forecasts such that the annual ratio between the zone substation non-coincident forecasts is within the 90 per cent confidence level.

SKM's analysis indicated a mean value of, 0.9606 with a 90 per cent confidence interval of +/-0.026 (i.e. a range of 0.9346 to 0.9866).[211] The final ratios are shown in the following Table 4.6.

[211] SKM, CitiPower/Powercor Demand Forecasts, 8 July 2010 (Attachment 50 to this Revised Regulatory Proposal), p18.

50% PoE forecasts (MW)	2011	2012	2013	2014	2015
NIEIR system[212]	1431	1469	1516	1557	1594
CitiPower zone substation non-coincident[213]	1517	1559	1627	1669	1711
Ratio	0.943	0.942	0.931	0.933	0.931

Table 4.6 Reconciliation of NIEIR system maximum forecasts and CitiPower's non-coincident maximum demand forecasts, 50% PoE

The comparison in Table 4.6 indicates that the ratio of CitiPower's spatial forecasts and the NIEIR system level forecasts is consistent with the bottom bound of the 90 per cent confidence interval determined by SKM (0.9346).[214] This confirms that CitiPower's non-coincident zone substation forecasts for the period 2011-15 are consistent with a top-down reconciliation against NIEIR's system level maximum demand forecasts. This also confirms that the zone substation forecasts included in the Initial Regulatory Proposal across all areas of the network, with the exception of the Fisherman's Bend area, were an accurate representation of the expected growth in maximum demand.

The forecasts from Table 4.6 are illustrated in Figure 4.3 below, together with actual maximum demand from 2006-10.

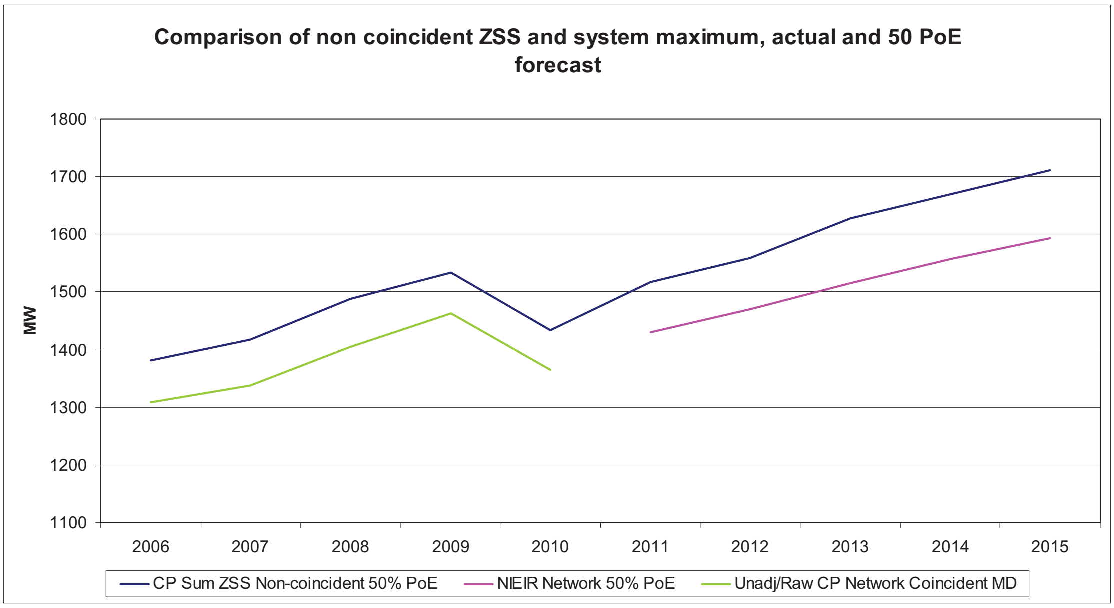

Figure 4.3 NIEIR's system maximum demand forecasts and CitiPower's non-coincident zone substation maximum demand forecasts, 50% PoE

4.4.4 CitiPower's Revised Regulatory Proposal

The maximum demand forecasts included in CitiPower's Revised Regulatory Proposal are set out in the following Table 4.7.

[212] Revised Regulatory Template 6.3 (Table 12).
[213] Revised Regulatory Template 6.3 (Table 32).
[214] CitiPower notes SKM's comments that, while SKM selected a 90 per cent confidence interval, more conservative values of 95 per cent or event 99 per cent could be used: SKM, CitiPower / Powercor Demand Forecasts, 8 July 2010 (Attachment 50 to this Revised Regulatory Proposal), p37 (Appendix A).

	2011	2012	2013	2014	2015
Maximum demand (MW)	1,517	1,559	1,627	1,669	1,711

Table 4.7 Maximum demand forecasts included in the Revised Regulatory Proposal

4.5 Customer number forecasts

4.5.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower adopted the customer number forecasts prepared by NIEIR which are set out in the report entitled Electricity sales and customer number projections for the CitiPower region to 2019.[215]

CitiPower used NIEIR's customer number forecasts to prepare its new customer connection capex forecasts and to calculate the scale escalator applied to its opex forecasts.

4.5.2 AER's Draft Determination

ACIL Tasman did not reach a conclusion as to the reasonableness of the customer number forecasts reflected in CitiPower's Initial Regulatory Proposal.[216]

While ACIL Tasman recommended that NIEIR's energy consumption forecasts be re-estimated with the ABS' 'series B' population forecasts as an input, ACIL Tasman noted that it would not expect to see a substantial change in NIEIR's customer number forecasts if they were re-estimated with ACIL Tasman's preferred population forecasts.[217]

The AER found that NIEIR's forecasts predict a continuation of recent historical trends, which the AER considered was reasonable.[218] The AER went on, however, to state that:[219]

> *'The AER notes that the factors affecting GSP and population growth forecasts are also likely to affect NIEIR's customer number forecasts and therefore expects these will all be updated for the Victorian DNSPs' revised proposals.'*

4.5.3 CitiPower's response to the AER's Draft Determination

CitiPower's Revised Regulatory Proposal reflects the updated forecasts prepared by NIEIR, which are set out in its report, Electricity sales and customer number projections for the CitiPower region to 2019, June 2010.[220] CitiPower considers that the AER can be satisfied NIEIR's customer numbers forecasts for the next regulatory control period are reasonable because the macro-economic indicators used in the model to develop the forecasts included:

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[215] Attachment P0005 to the Initial Regulatory Proposal.
[216] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, Final report, 11 May 2010, pp58-9.
[217] ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, Final report, 11 May 2010, p59.
[218] AER, Draft Determination, p99.
[219] AER, Draft Determination, p99. The AER reiterated its position on page 156 of the Draft Determination.
[220] NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), pp100-1 (Table 8.4).

- population growth forecast across Victoria in the next regulatory control period of 1.4 per cent, which is consistent with the ABS' 'series B' population growth forecast that ACIL Tasman and the AER recommended be used; and
- updated forecasts of economic growth, which, for the reasons outlined earlier in this Chapter are reasonable.

4.5.4 CitiPower's Revised Regulatory Proposal

The customer numbers forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 4.8 below.

	2011	2012	2013	2014	2015
Customer numbers	316,818	322,742	327,190	331,100	337,050

Table 4.8 Customer numbers forecasts included in the Revised Regulatory Proposal

4.6 CitiPower's Revised Regulatory Proposal

In preparing its Revised Regulatory Proposal, CitiPower has used the forecasts of energy consumption, maximum demand and customer numbers set out in Table 4.9.

	2011	2012	2013	2014	2015
Energy consumption (GWh)	6,177	6,210	6,182	6,148	6,177
Maximum demand (MW)[221]	1,517	1,559	1,627	1,669	1,711
Customer numbers	316,818	322,742	327,190	331,100	337,050

Table 4.9 CitiPower's energy consumption, maximum demand and customer numbers forecasts for 2011-15 included in the Revised Regulatory Proposal

[221] Summation of non-coincident zone substation and 22kV terminal station points of supply, maximum demands.

5. OUTSOURCING ARRANGEMENTS

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to the findings in Chapter 6 of, and section H.2 of Appendix H to, the AER's Draft Determination in respect of expenditure payable by CitiPower under its outsourcing arrangements. In particular, this Chapter responds to the AER's decision to exclude the margin payable by CitiPower under its outsourcing arrangements from the derivation of its forecast opex and capex for the 2011-15 regulatory control period.

5.1 Summary of key points

For the reasons cited by the AER in the Draft Determination, CitiPower accepts the following of the AER conclusions in the Draft Determination:

- the margin payable by CitiPower under the aforementioned contracts should be **excluded** from the calculation of the efficiency carry over mechanism amounts for the period 2006-09; and
- the margin payable by CitiPower under the aforementioned contracts should be **included** in the 2006-09 actual capex that is used in RAB roll forward calculation.

In addition, for the purposes of this Revised Regulatory Proposal only, CitiPower does not contest the AER's decision in the Draft Determination to exclude the administration fee payable by CitiPower under the DRMS with CHED Services from its expenditure forecasts for the 2011-15 regulatory control period and from the calculation of the EBSS carry over amounts for 2011-15.[222]

However, CitiPower does not accept the AER's decision in the Draft Determination to exclude the margins payable under its Corporate Services Agreement with CHED Services, its Network Services Agreement with PNS and its Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, from its opex and capex forecasts for the 2011-15 regulatory control period and from the calculation of the EBSS carry over amounts for 2011-15.

CitiPower maintains that the AER should accept the forecasts of total opex and capex included in this Revised Regulatory Proposal without making any adjustment to reduce the expenditure payable by CitiPower to CHED Services under the Corporate Services Agreement, PNS under the Network Services Agreement and Silk Telecom under the Electrical Network Communications Agreement and Corporate Communications Agreement to exclude margins. More specifically, CitiPower maintains that:

[222] CitiPower observes that, as discussed in detail in section 5.5.3 below, the administration fee payable to CHED Services under the DRMS was not included in the expenditure forecasts for the 2011-15 regulatory control period proposed in CitiPower's Initial Regulatory Proposal.

- its forecast expenditure inclusive of the margins payable to CHED Services, PNS and Silk Telecom under these Agreements satisfies the opex and capex criteria;
- the margins payable under these Agreements with CHED Services, PNS and Silk Telecom should be included in its opex and capex forecasts for the 2011-15 regulatory control period; and
- the margins payable under these Agreements with CHED Services, PNS and Silk Telecom should be included in the calculation of the EBSS carry over amounts for the 2011-15 regulatory control period.

In particular, CitiPower maintains that the AER must accept its forecast opex inclusive of any expenditure incurred under the Corporate Services Agreement with CHED Services, the Network Services Agreement with PNS and the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, including the implied margins, without adjustment because:

- the opex criteria, properly construed, do not permit the AER to reduce a DNSP's total expenditure forecasts, for example to exclude margins under outsourcing arrangements, below the efficient costs of achieving the opex objectives; and
- benchmarking analysis conducted by NERA establishes that CitiPower's forecast opex for 2011-15 set out in its Initial Regulatory Proposal inclusive of any expenditure under the Corporate Services Agreement with CHED Services, the Network Services Agreement with PNS and the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, including implied margins, is efficient.

In addition, CitiPower maintains that the AER must accept its forecast expenditure under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, including the implied margins, without adjustment because:

- Contrary to the AER's conclusion, the decision by CitiPower and Powercor Australia to adopt their current service model, under which they pay a margin to CHED Services and PNS, was prudent at the time of that decision and remains prudent if assessed with the benefit of hindsight.
- The expenditure incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS inclusive of margins is prudent and efficient because:
    - the NEL and the Rules, properly construed and applied, require the AER to adopt the stand-alone, in-house cost of service provision (and do not permit the AER to adopt the costs that would be incurred by the group to which the DNSP belongs) as the benchmark or counterfactual for assessing forecast opex and capex

under outsourcing arrangements that fail the 'presumption threshold'; and

- the expenditure incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS inclusive of margins is lower than the stand-alone, in-house cost of service provision.

- Even if (contrary to CitiPower's contentions) the AER maintains its view that the Rules permit it to consider the costs that would be incurred by the group rather than the individual DNSP, CitiPower would nonetheless maintain that the margins payable under the Corporate Services Agreement and the Network Services Agreement should be included, at least in part, in its expenditure forecasts for 2011-15 because:
  - the AER cannot, acting reasonably, take into account efficiencies accruing to a contractor from the provision of services to third parties in circumstances where the AER must exclude the costs associated with the provision of unregulated services from allowed opex and capex; and
  - PNS derived a significant portion of its revenue in 2009 from the supply of services to third parties.
- The margins payable under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS reflect the margins that would be expected to be agreed to by parties operating on an arm's length basis because:
  - contrary to the AER's conclusion, Ernst & Young's analysis of the profit on direct and indirect costs earned by companies providing comparable services to third parties is just as relevant in an economic regulatory context as in a taxation context; and
  - the benchmark margins calculated by Ernst & Young in this manner were adopted as the margins payable under the Corporate Services Agreement and the Network Services Agreement.
- The AER should take additional comfort that the Corporate Services Agreement and the Network Services Agreement were not entered into for the purposes of transfer pricing or to otherwise agree to non arm's length terms from the following:
  - the non-price terms and conditions of the Agreements are of an arm's length nature; and
  - the Agreements accord CHED Services and PNS with appropriate incentives and ensure that the benefits of any cost savings are passed through to CitiPower and, in turn, users.

5.2 Rule requirements

The AER's assessment and treatment of a DNSP's forecast opex and capex for a regulatory control period is governed by:

- the NEO and the revenue and pricing principles set out in the NEL; and
- the provisions of the Rules governing the AER's assessment of total opex and capex forecasts set out in the building block proposal in the DNSP's regulatory proposal.

These limitations on the AER's assessment of a DNSP's opex and capex forecasts are discussed, in turn, below.

5.2.1 Relevant NEL provisions

When making the Final Determination, the AER is required to take into account the NEO and the revenue and pricing principles in the NEL.

The NEO is set out in section 7 of the NEL. The revenue and pricing principles are set out in section 7A of the NEL. The revenue and pricing principles include, in particular, section 7A(2) which provides as follows:

> *A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> *(a) providing direct control network services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.'*

5.2.2 Relevant provisions of the Rules

The AER's assessment of outsourcing arrangements must be undertaken in accordance with those Rules that govern the assessment of a DNSP's opex and capex forecasts. The rules pertaining to forecast opex are set out in clause 6.5.6 of the Rules while the rules pertaining to forecast capex are set out in clause 6.5.7.

Clause 6.5.6(c) of the Rules requires the AER to accept the forecast of required opex that is included by a DNSP in its 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 'operating expenditure objectives' are set out in clause 6.5.6(a) of the Rules.

It is only if the AER is not satisfied that the total opex for the regulatory control period reasonably reflects the opex criteria that the AER may reject the DNSP's forecast opex and itself estimate the total of the DNSP's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors (clauses 6.5.6(d) & 6.12.1(4)).

In deciding whether or not the AER is satisfied that the total opex for the regulatory control period reasonably reflects the opex criteria, the AER must consider the matters set out in clause 6.5.6(e), referred to as the 'operating expenditure factors'. Of relevance to the AER's assessment of outsourcing arrangements are the following 'operating expenditure factors':

> *'(4)* *benchmark operating expenditure that would be incurred by an efficient* Distribution Network Service Provider *over the* regulatory control period*;*
>
> *(9)* *the extent the forecast of required operating expenditure of the* Distribution Network Service Provider *is referable to arrangements with a person other than the provider that, in the opinion of the* AER*, do not reflect arm's length terms.'*

Clauses 6.5.7 and 6.12.1(3) of the Rules contain analogous provisions in respect of the AER's assessment of a DNSP's forecast capex.

5.3 CitiPower's Initial Regulatory Proposal

Within its Initial Regulatory Proposal, CitiPower noted that it had sought to adopt a service model that would enable it to better focus on its long term asset ownership and performance[223] and that, in doing so, it had entered into the following arrangements with related entities:

- Corporate Services Agreement – this Agreement was entered into in 2008 with CHED Services. Under the terms of this Agreement, CHED Services provides specialist corporate services to CitiPower, including the Chief Executive Officer, Finance, the Company Secretary, Legal, Human Resources, Corporate Affairs, Regulation, Customer Services, Information Technology and Office Administration;
- Network Services Agreement – this Agreement was entered into in 2008 with PNS. Under the terms of this Agreement, PNS provides construction and maintenance services, including customer and connection services, asset replacement maintenance services, asset performance (fault services) and network development services to CitiPower; and
- DRMS – this Scheme was put in place in 2004. Under the terms of the Scheme, CHED Services provides in-fill insurance cover to CitiPower in respect of motor vehicle insurance and amounts below the policy deductibles for the following external insurance policies: liability insurance; and property insurance.

CitiPower considered these arrangements were efficient on the basis that:

[223] Initial Regulatory Proposal, p357.

- they complied with principles established by CitiPower's Board for the engagement of related parties;[224]
- the margins under the arrangements were paid in accordance with arm's length transfer prices determined by independent expert, Ernst & Young;[225] and
- independent advice from KPMG indicated that had CitiPower delivered its nominated services for the year ended 31 December 2008 on an in-house stand-alone basis, the cost of service delivery would have been [redacted] per cent higher than the comparable actual direct costs incurred in that year.[226]

5.4 AER's Draft Determination

Chapter 6 of the AER's Draft Determination sets out both its:

- proposed two stage inquiry process for assessing outsourcing contracts; and
- assessment of the outsourcing arrangements entered into by each DNSP.

Section H.2 of Appendix H to the Draft Determination sets out the AER's detailed assessment of CitiPower's outsourcing arrangements.

5.4.1 Summary of AER's Findings

Based on its assessment of each of CitiPower's outsourcing agreements, the AER concluded in its Draft Determination that the margins payable under the following arrangements entered into by CitiPower did not reasonably reflect the opex criteria and the capex criteria set out in clauses 6.5.6(c) and 6.5.7(c) of the Rules respectively:

- the Corporate Services Agreement with CHED Services;
- the Network Services Agreement with PNS;
- the DRMS with CHED Services; and
- the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom.

Having formed this view the AER excluded the margins payable by CitiPower under these arrangements from the calculation of:

- forecast opex and capex for the 2011-15 regulatory control period;[227] and
- the EBSS carry over amounts for the 2011-15 regulatory control period.[228]

In addition, the AER excluded the margins payable by CitiPower under these arrangements from actual opex for 2006-09 in calculating the efficiency carry

[224] Initial Regulatory Proposal, p355.
[225] Initial Regulatory Proposal, pp349-50.
[226] KPMG, The efficiencies of the CitiPower Service Model, September 2009 (Attachment C0053 to the Initial Regulatory Proposal), p12.
[227] AER, Draft Determination, section 6.6.1, pp191-2; AER, Draft Determination Appendices, Appendix H, section H.2, pp25-33.
[228] AER, Draft Determination, section 6.5.8, p190.

over amounts arising from the 2006-09 regulatory period to be carried forward for 2011-15. The AER did so because this is necessary to allow a 'like for like' comparison with the ESCV's opex forecasts for 2006-09, not on the basis of its assessment of those arrangements in its Draft Determination.[229]

Further, while the AER excluded the margin from the calculation of the items referred to above, the margin payable for capex over the period 2006-09 was **retained** in the RAB roll forward calculation. The AER retained these margins because it (correctly) conceded that this is required by clause 6.2.1(e)(1) of the Rules.[230]

The remainder of this section provides an overview of the AER's two stage assessment framework and the conclusions reached by the AER on CitiPower's outsourcing arrangements.

5.4.2 AER's two stage assessment framework

Sections 6.5.1 to 6.5.4 of the Draft Determination describe the AER's two stage approach to the assessment of outsourcing arrangements. Figure 5.1 below provides a summary of the pertinent features of the AER's proposed framework.

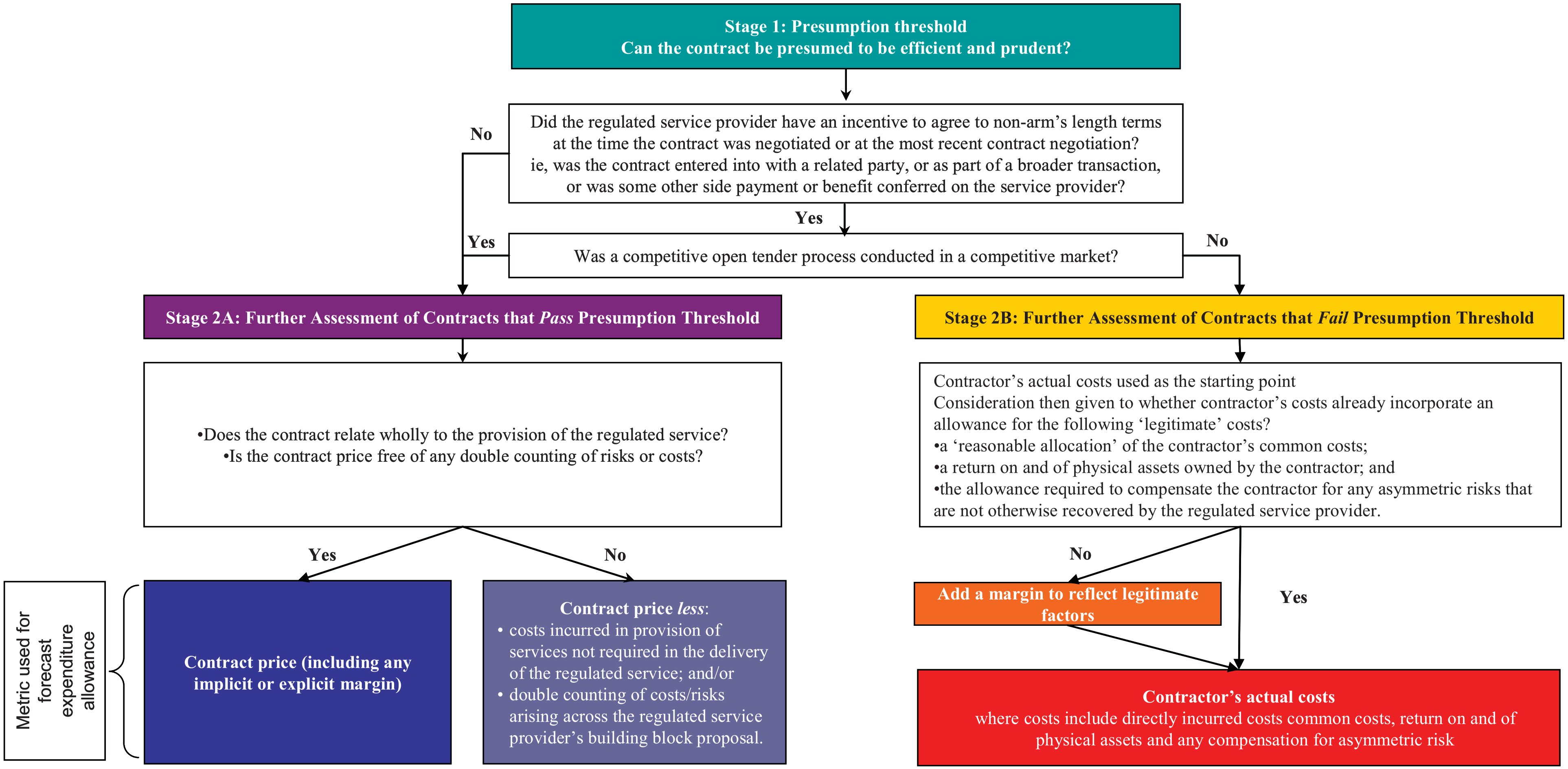
At its most elementary this framework consists of a two stage inquiry process, which in the first stage involves distinguishing between those contracts entered into by a regulated service provider that can be presumed to *'reflect efficient costs and costs that would be incurred by a prudent operator'* and those that cannot (referred to as the 'presumption threshold'). This assessment requires consideration to be given to the following questions:[231]

- Did the DNSP have an incentive to enter into a non-arm's length contract at the time the contract was negotiated (or at its most recent renegotiation)? Circumstances that the AER has noted could give rise to an incentive to enter into such arrangements include:[232]
    - where the parties to the contract were related at the time the contract was negotiated (or re-negotiated);
    - where the contract was entered into as part of a broader transaction; or
    - where the contractor conferred some form of benefit on the regulated service provider in return for it agreeing to pay an artificially inflated price.
- If a DNSP is found to have such an incentive, then the second question that must be addressed is whether the contract was the subject of an open tender process conducted in a competitive market to obtain the contract. Where a DNSP is found to have had an incentive to enter into a non-arm's length

[229] AER, Draft Determination, section 6.5.6, p188.
[230] AER, Draft Determination, section 6.5.7, pp188-90.
[231] AER, Draft Determination, p170.
[232] AER, Draft Determination, p170.

contract and the contract was not subject to an open tender process, then the contract is treated as having failed the 'presumption threshold'.

Figure 5.1: AER's Proposed Framework for Assessing Outsourcing Arrangements



Source: AER, Draft Determination, pp168-186.

The second stage of the AER's framework requires a more detailed review of the contracts entered into by the DNSP to determine whether the margin payable under a contract should be included when deriving the DNSP's forecast opex and/or capex. Under the AER's proposed approach a distinction has been drawn between the manner in which margins will be treated in those contracts that pass the 'presumption threshold' and those that do not:[233]

> *'In summary, the AER's approach involves the following assessment:*
>
> - *where a contract passes the presumption threshold - the 'starting point' for setting future expenditure allowances should be the contract price itself, with limited further examination required. This further examination involves checking whether the contract wholly relates to the relevant services (for example, .standard [sic] control services) and whether the (efficiently presumed) contract price already compensates for risks or costs provided for elsewhere in the building blocks.*
> - *where a contract fails the presumption threshold - the 'starting point' for setting future expenditure allowances should be the contractor's actual costs itself, with a 'margin' above this level permitted only where the service provider is able to establish the efficiency and prudency of such a margin against legitimate economic reasons for the inclusion of the margin (including its quantum).'*

Those factors cited by the AER as being 'legitimate' and therefore warranting the payment of an amount in excess of the contractor's directly incurred costs, in circumstances where the contract fails the presumption threshold, include:[234]

- the allowance required to enable the contractor to recover a 'reasonable allocation' of its common costs;
- the return on and of capital required to compensate the contractor for the use of assets that are employed in the provision of services to the DNSP that are owned by the contractor and are not included in the DNSP's RAB; and
- the allowance required by the contractor to self insure against asymmetric risks arising under the contract provided that these risks are not reflected elsewhere in the DNSP's building block proposal.

The AER concluded that, with the exception of any future expected but currently unrealised efficiencies accruing in the forthcoming (i.e. 2011-15) regulatory control period, scale, scope and other efficiencies do not warrant the payment of an amount in excess of the contractor's directly incurred costs for two reasons as follows:

[233] AER, Draft Determination, p169.
[234] AER, Draft Determination, pp.180-2, 186.

- First, the AER reasoned that:[235]
    - it is permitted by the Rules, in particular by the prudency criterion that is one of the three opex and capex criteria, to assess forecasts having regard to the costs that would be incurred by the group to which the DNSP belongs rather than the costs that would be incurred if the services were provided on a 'fully in-sourced, stand-alone' basis; and
    - efficiencies, such as merger synergies, should be retained for a period of time by the DNSP but eventually passed through to consumers.
- Secondly, the AER reasoned that:[236]
    - pricing under outsourcing arrangements is efficient if that pricing is set in a workably competitive market through an open, competitive tender process or mimics pricing outcomes that would prevail in a workably competitive market; and
    - *'in a workably competitive market a contractor could not [charge a premium (i.e. a margin) above its full economic costs and] earn abnormal profits in the long run for efficiencies it has realised in the past'*.

Accordingly, the AER's approach to a contractor's scale, scope and other efficiencies is to use the contractor's actual historical costs (both direct and common), including historical and realised efficiencies but ignoring future expected but currently unrealised efficiencies accruing in the forthcoming regulatory control period, in:[237]

- assessing whether DNSPs' forecast opex and capex, and forecasting substitute opex and capex that, reasonably reflects the opex and capex criteria; and
- actual opex in the forthcoming regulatory control period used at the end of that period to calculate the EBSS payments for that period.

5.4.3 Assessment of the Corporate Services Agreement

The AER's detailed assessment of the Corporate Services Agreement with CHED Services is set out in section H.2.2 of Appendix H to the Draft Determination.

In summary, the application of the AER's assessment framework to the Corporate Services Agreement prompted it to reach the following conclusions:

- the Agreement did not pass the presumption threshold;
- the margin payable under the Agreement was in excess of CHED Service's common costs and did not relate to a return of or on assets owned by CHED Services; and

[235] AER, Draft Determination, pp178-9.
[236] AER, Draft Determination, p182.
[237] AER, Draft Determination, pp182-3.

- prior to the establishment of CHED Services, the services provided under the Corporate Services Agreement were provided by Powercor Australia to itself and CitiPower 'at cost' and so Powercor Australia could have secured the same economies of scale and scope, and other efficiencies as those available to CHED Services without payment of a margin, with the result that no margin would be incurred by a prudent operator in Powercor Australia's circumstances.[238] While not expressly stated in the Draft Determination, it would appear that the AER would consider CitiPower's decision to adopt its current service model, under which it pays a margin to CHED Services and PNS, as imprudent for analogous reasons.

On the basis of the foregoing, the AER concluded that the margin payable under the Corporate Services Agreement should be **excluded** from the derivation of CitiPower's opex and capex forecasts for the 2011-15 regulatory control period.

In this section of the Draft Determination, the AER also considered the relevance of the Ernst & Young reports commissioned by CitiPower and Powercor Australia, which were used to determine the initial margins payable under the Corporate Services Agreement.[239] The AER ultimately concluded that no reliance could be placed on the findings in these reports because differences in the objectives underpinning the tax and economic regulatory regimes meant that it could not be *'assumed that practices which are appropriate in a tax context are always appropriate in an economic regulatory context'*.[240]

5.4.4 Assessment of the Network Services Agreement

The AER's detailed assessment of the Network Services Agreement with PNS is set out in section H.2.4 of Appendix H to the Draft Determination.

In a similar manner to the Corporate Services Agreement, the application of the AER's framework resulted in the Network Services Agreement being deemed to fail the presumption threshold and the margin payable under this agreement being excluded from CitiPower's opex and capex forecasts for 2011-15. The basis for this decision is directly analogous to that set out in the preceding section in respect of the Corporate Services Agreement.[241]

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[238] AER, Draft Determination, Appendix H, pp26-7.

[239] Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment C0049 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Customer Services (Excluding Metering), 20 November 2006 (Attachment C0050 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services), 20 November 2006 (Attachment C0051 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 21 May 2009 (Attachment C0052 to the Initial Regulatory Proposal). As discussed in the Initial Regulatory Proposal (at p350), in the May 2009 report by Ernst & Young, it updates the benchmark IT margin previously provided in its November 2006 report in respect of IT services and indicates that there has been little movement in the benchmark IT margin over the intervening period.

[240] AER, Draft Determination, pp187-8 and Appendix H at p26.

[241] The relevant Ernst & Young report in respect of the Network Services Agreement with PNS is Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and

5.4.5 Assessment of the Discretionary Risk Management Scheme

The AER's detailed assessment of the DRMS with CHED Services is set out in section H.2.3 of Appendix H to the Draft Determination.

The application of the AER's framework to this arrangement led it to conclude that:

- the arrangement failed the presumption threshold; and
- the margin payable to CHED Services should be excluded from CitiPower's opex forecasts for the 2011-15 regulatory control period because a share of CHED Services' overheads was already included in CitiPower's base capex and opex forecasts and CHED Services did not appear to own any assets that were not already included in CitiPower's RAB.

In its assessment of this arrangement, the AER noted that the transfer of risk arising under this arrangement from CitiPower to CHED Services was not significant given the deductibles only relate to relatively low value amounts.[242] The AER therefore concluded that, while external insurance providers would charge both an administration fee to cover the insurer's administration costs and a profit margin, the margin payable to CHED Services for the DRMS was not prudent because the arrangement did not deliver *'significant cost-smoothing benefits'* relative to the situation if CitiPower retained the risks.[243]

5.4.6 Assessment of the Electrical Network Communications Agreement and Corporate Communications Agreement

The AER's detailed assessment of CitiPower's Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom is set out in section H.2.8 of Appendix H to the Draft Determination.

While Silk Telecom is no longer related to CitiPower, the AER concluded that, because the parties were related at the time the contracts were entered into, the contracts should be treated as having failed the presumption threshold. The AER also considered whether the decision by CitiPower not to trigger the contract price review provisions following the change of ownership of Silk Telecom could be viewed as confirming that the prices set within these contracts were those that would have been agreed if the parties were **not** related. The AER concluded, however, that given nature of the contract price review provisions, it could not form such a view. The contracts were therefore treated as having failed the presumption threshold.[244]

Maintenance Services, 30 November 2006 (Attachment C0048 to the Initial Regulatory Proposal). It was considered by the AER in its Draft Determination in Appendix H at p29.

[242] AER, Draft Determination Appendices, Appendix H, p28.

[243] AER, Draft Determination Appendices, Appendix H, p28.

[244] AER, Draft Determination Appendices, Appendix H, p32.

The AER then considered whether any margin would be warranted for a return on or of assets owned by Silk Telecom, or to enable it to recover a reasonable share of its common costs. On the first of these issues, the AER noted that it was not aware of Silk Telecom owning any assets and so no margin would be required for this reason.[245] On the issue of common costs, the AER noted that an unsupported percentage margin above costs for corporate costs was not *'sufficient substantiation that the quantum of corporate costs proposed reasonably reflect efficient costs that would be incurred by a prudent operator'*.[246] The AER therefore excluded the margin payable under these arrangements from CitiPower's forecast opex and capex for the 2011-15 regulatory control period but left the door open to CitiPower to provide evidence to demonstrate that some, or all, of the margin payable to Silk Telecom related to its recovery of common costs.

5.5 CitiPower's response to the AER's Draft Determination

For the reasons cited by the AER, CitiPower accepts the following of the AER conclusions in the Draft Determination:

- the margin payable by CitiPower under the aforementioned contracts should be **excluded** from the calculation of the efficiency carry over mechanism amounts for the period 2006-09; and
- the margin payable by CitiPower under the aforementioned contracts should be **included** in the 2006-09 actual capex that is used in RAB roll forward calculation.

In addition, for the purposes of this Revised Regulatory Proposal only, CitiPower does not contest the AER's decision in the Draft Determination to exclude the administration fee payable by CitiPower under the DRMS with CHED Services from its expenditure forecasts for the 2011-15 regulatory control period and from the calculation of the EBSS carry over amounts for 2011-15.[247]

However, CitiPower does not accept the AER's decision in the Draft Determination to exclude the margins payable under its Corporate Services Agreement with CHED Services, its Network Services Agreement with PNS and its Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, from its opex and capex forecasts for the 2011-15 regulatory control period and from the calculation of the EBSS carry over amounts for 2011-15.

[245] AER, Draft Determination Appendices, Appendix H, p33.
[246] AER, Draft Determination Appendices, Appendix H, p33.
[247] CitiPower observes that, as discussed in detail in section 5.5.3 below, the administration fee payable to CHED Services under the DRMS was not included in the expenditure forecasts for the 2011-15 regulatory control period proposed in CitiPower's Initial Regulatory Proposal.

CitiPower maintains that the AER should accept the forecasts of total opex and capex included in this Revised Regulatory Proposal without making any adjustment to reduce the expenditure payable by CitiPower to CHED Services under the Corporate Services Agreement, PNS under the Network Services Agreement and Silk Telecom under the Electrical Network Communications Agreement and Corporate Communications Agreement to exclude margins. More specifically, CitiPower maintains that:

- its forecast expenditure inclusive of the margins payable to CHED Services, PNS and Silk Telecom under these Agreements satisfies the opex and capex criteria;
- the margins payable under these Agreements with CHED Services, PNS and Silk Telecom should be included in its opex and capex forecasts for the 2011-15 regulatory control period; and
- the margins payable under these Agreements with CHED Services, PNS and Silk Telecom should be included in the calculation of the EBSS carry over amounts for the 2011-15 regulatory control period.

In particular, CitiPower maintains that the AER must accept its forecast opex inclusive of any expenditure incurred under the Corporate Services Agreement with CHED Services, the Network Services Agreement with PNS and the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, including the implied margins, without adjustment because:

- the opex criteria, properly construed, do not permit the AER to reduce a DNSP's total expenditure forecasts, for example to exclude margins under outsourcing arrangements, below the efficient costs of achieving the opex objectives; and
- benchmarking analysis conducted by NERA establishes that CitiPower's forecast opex for 2011-15 set out in its Initial Regulatory Proposal inclusive of any expenditure under the Corporate Services Agreement with CHED Services, the Network Services Agreement with PNS and the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, including implied margins, is efficient.

In the remainder of this section 5.5, CitiPower responds, in turn, to:

- the AER's two stage assessment framework;
- the AER's assessment of CitiPower's Corporate Services Agreement with CHED Services and its Network Services Agreement with PNS;
- its assessment of the DRMS with CHED Services; and
- its assessment of CitiPower's Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom.

5.5.1 Response to the AER's two stage assessment framework

CitiPower maintains that the AER's two stage assessment framework for outsourcing arrangements, specifically the AER's treatment of scale and scope, and other, efficiencies available to the contractor at the second stage of its assessment framework, is flawed.

As discussed above, the AER concluded in the Draft Determination that, for outsourcing arrangements that fail the AER's first stage 'presumption threshold', scale, scope and other efficiencies do not warrant the payment of an amount in excess of the contractor's directly incurred costs, with the exception only of any future expected but currently unrealised efficiencies accruing in the forthcoming (i.e. 2011-15) regulatory control period. The AER adopted this approach in the second stage assessment of such arrangements because it reasoned that:

- the AER is permitted by the Rules, in particular by the prudency criterion that is one of the three opex and capex criteria, to assess forecasts having regard to the costs that would be incurred by the group to which the DNSP belongs and that efficiencies, such as merger synergies, should be retained for a period of time by the DNSP but eventually passed through to consumers; and
- pricing under outsourcing arrangements is efficient if that pricing is set in a workably competitive market through an open, competitive tender process or mimics pricing outcomes that would prevail in a workably competitive market, and *'in a workably competitive market a contractor could not [charge a premium (i.e. a margin) above its full economic costs and] earn abnormal profits in the long run for efficiencies it has realised in the past'*.

CitiPower has identified the following flaws with respect to this aspect of the AER's second stage assessment:

- It is legally impermissible for the AER to adopt the costs that would be incurred by the group to which the DNSP belongs as a benchmark or counterfactual against which to assess Victorian DNSPs' expenditure under outsourcing arrangements that fail the AER's first stage 'presumption threshold'.
- The AER's application of theory regarding pricing outcomes in workably competitive markets is erroneous, including in particular by reason of the fact that, in applying that theory, the AER assumes that the long run is any period in excess of a 5 year regulatory control period, which assumption is contrary to observed commercial practices in workably competitive markets and a prior Tribunal decision.
- The AER's approach to scale and scope, and other, efficiencies in its second stage assessment:
    - does not recognise the potential for outsourcing arrangements that are deemed to fail the first stage 'presumption threshold' to be an efficient means of service delivery; and

  - o as a result, creates perverse incentives for DNSPs to bring their operations in-house where the outsourcing arrangement is a more efficient means of service delivery.

- The AER's approach is inconsistent with previous regulatory decisions by itself and the ESCV.

CitiPower elaborates below on each of these flaws in the second stage of the AER's two stage assessment framework and then sets out the alternate assessment framework that the AER should apply to outsourcing arrangements that fail the AER's first stage 'presumption threshold'.

5.5.1.1 Benchmark or counterfactual of costs incurred by group is legally impermissible

CitiPower disagrees with the AER's construction and application of the opex and capex criteria and believes that its erroneous construction and application of these criteria has led the AER to **incorrectly** conclude that the costs that would be incurred by the **group** to which the DNSP belongs should be adopted as the benchmark or counterfactual against which a DNSP's forecast of opex and capex under outsourcing arrangements that fail the first stage 'presumption threshold'.

The opex and capex criteria include both an efficiency criterion and a prudency criterion (as well as a third criterion which is of no relevance to the AER's assessment of related party expenditure included in a DNSP's expenditure forecasts and, accordingly, will not be considered further in this section 5.5.1.1).

The AER's construction and application of these criteria are critical to its conclusion in the Draft Determination that the margins payable by CitiPower under its various outsourcing arrangements should be excluded from its opex and capex forecasts for the 2011-15 regulatory control period. Accordingly, CitiPower sets out in Appendix 5.1 to this Revised Regulatory Proposal detailed legal analysis and conclusions on:

- the proper construction and application of the prudency criterion;
- the proper construction and application of the efficiency criterion; and
- the AER's discretion to balance the competing efficiency and prudency criteria.

CitiPower's legal analysis, set out in Appendix 5.1, demonstrates that the AER erred in the Draft Determination in concluding that:

- the Rules permit it to assess a DNSP's expenditure forecasts having regard to the costs that would be incurred by the group to which the DNSP belongs rather than the costs that would be incurred in the services were provided on a 'fully in-sourced, standalone' basis or the costs that would be incurred by the DNSP itself having regard to its group structure; and

- the efficient costs of the DNSP would not include any margin above its contractor's directly incurred costs in respect of scale, scope and other efficiencies, with the exception only of any future expected but currently unrealised efficiencies accruing in the forthcoming (i.e. 2011-15) regulatory control period, because such a margin could not be charged by that contractor in a workably competitive market.

Briefly stated, CitiPower's views on the proper construction and application of the prudency and efficiency criteria and the AER's discretion to balance these competing criteria are as follows:

- The phrase *'in the circumstances of the relevant* Distribution Network Service Provider', where it appears in the prudency criterion, does not permit the AER to have regard to the group structure of a DNSP in assessing its expenditure forecasts because:
    - in properly construing this phrase, a purposive rather than a literal interpretation must be adopted; and
    - the circumstances of the DNSP to which the prudency criterion refers were intended to require a consideration of the network operating conditions of the DNSP and not its group structure.
- In any event, even if the circumstances of the DNSP referred to in the prudency criterion include the group structure of the DNSP, it does not follow that the prudency criterion permits the AER to assess the DNSP's expenditure forecasts against the costs that would be incurred by the group to which the DNSP belongs because:
    - the prudency criterion refers to *'the circumstances of the relevant* Distribution Network Service Provider' and not to the circumstances of the group to which that DNSP belongs and, accordingly, requires an inquiry into the costs that the DNSP itself (as distinct from the group to which it belongs), acting prudently, would require to achieve the opex and/or capex objectives;
    - it cannot be assumed that scale and scope efficiencies achievable by the group are necessarily available at no cost to the DNSP, acting prudently; and
    - it follows that the AER cannot exclude any scale and scope efficiencies achievable by the group to which a DNSP belongs from the benchmark costs against which a DNSP's expenditure forecasts are assessed in applying the prudency criterion, except where the AER satisfies itself that those efficiencies could be accessed without cost (i.e. margin) by the DNSP, acting prudently.
- While CitiPower accepts that the efficiency criterion, properly construed and applied, necessitates an inquiry into pricing outcomes in a workably competitive market, it disagrees with the AER that it follows that efficiencies realised by another entity in the group to which the DNSP belongs in the current or previous regulatory control periods do not warrant payment of an amount in excess of the contractor's directly incurred costs.

To the contrary, the decision of the Tribunal in *Application by Optus Mobile Pty Limited and Optus Networks Pty Limited*[248] establishes that, in a workably competitive market, a service provider may gain a competitive advantage by having access to economies of scale and scope by reason of its ownership and operation of other networks in addition to the regulated network such that the stand-alone, in-house costs of service provision is the cost benchmark that best reflects the pricing outcomes that would prevail in a workably competitive market.

- In striking a reasonable balance between the efficiency and prudency criteria, the AER has no discretion to reduce a DNSP's expenditure forecasts below the efficient costs of achieving the opex and capex objectives, on the basis of its assessment of that expenditure forecast against the prudency criterion, because:
    - in exercising its discretion to balance the efficiency and prudency criteria, the AER must do so in a manner that is likely to contribute to the achievement of the NEO and takes into account the revenue and pricing principles;[249] and
    - the Tribunal concluded in *Application of Energy Australia and Others* that the NEO and the revenue and pricing principles require that the regulatory setting of prices *'err on the side of allowing at least the recovery of efficient costs'*.[250]

CitiPower is therefore of the opinion that the opex and capex criteria, properly construed and applied, require the AER to adopt the stand-alone, in-house cost of service provision as the benchmark or counterfactual for assessing forecast opex and capex under outsourcing arrangements that fail the 'presumption threshold', unless it can be demonstrated that the DNSP can access the economies of scale, scope and other efficiencies available to the group at no cost.

Even if the AER were to adopt a more stringent counterfactual than the stand-alone, in-house cost of service provision (which CitiPower does **not** concede is permissible under the Rules) then the AER should **not** take into account the efficiencies derived by the contractor from the provision of unregulated services or the provision of services to third parties when assessing a DNSP's forecast opex and capex under an outsourcing arrangement that fails the 'presumption threshold'. Just as the costs associated with the provision of unregulated services should not be taken into account when deriving forecasts for the standard control service neither should the benefits derived from the provision of these services.

5.5.1.2 Application of theory on workably competitive markets is erroneous

CitiPower accepts that:

[248] [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].
[249] NEL, section 16; [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [14] & [74].
[250] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal), at [78].

- pricing under outsourcing arrangements is efficient if that pricing is set in a workably competitive market through an open, competitive tender process or mimics the pricing outcomes that would prevail in a workably competitive market; and
- in a workably competitive market a contractor could not charge a premium above its full economic costs in the long run.

However, CitiPower disagrees with the AER's conclusion that, it follows from the application of these propositions to outsourcing arrangements, that scale and scope, and other, efficiencies realised by a contractor in the current or previous regulatory control periods would never warrant the payment of a margin to that contractor in the forthcoming regulatory control period.

In applying the theory regarding pricing outcomes in workably competitive markets, the AER has assumed that the long run is any period in excess of a 5 year regulatory control period. CitiPower considers that this assumption is erroneous because it is contrary to observed commercial practices in workably competitive markets and a prior Tribunal decision.

The most significant flaw in the AER's application of theory regarding pricing outcomes in workably competitive markets is that it fails to explain why in practice contractors continue to earn margins in excess of the amounts that the AER has categorised as forming a legitimate basis for a margin for periods exceeding the duration of a 5 year regulatory control period. The results of the benchmark EBIT margin study undertaken by NERA[251] and the EBIT margin analysis contained in a report prepared by Impaq[252] for the AER in the context of the current review are apposite.

The important point to recognise with EBIT margins is that they represent the margin available to an entity after paying their directly incurred expenses,

[251] The EBIT benchmark study undertaken by NERA in 2007 found that the majority of contractors in the sample consistently earned a margin in excess of their overheads and a return of capital with the average margin earned over the 2002-06 period being 5.5 per cent (see NERA, Allen Consulting Group's Review of NERA's Benchmarking of Contractors' Margins Critique, October 2007 (Attachment 98 to this Revised Regulatory Proposal), piv).

[252] In a report entitled 'Review of rates in proposed ACS Charges', dated 2 June 2010 (Attachment 227 to this Revised Regulatory Proposal), Impaq made the following observation at p38:

> *'ACS are not capital intensive and hence the application of the standard building blocks of Return of Capital and Return on Capital do not yield meaningful profit margins. However in similar service industries profit margins of from 3% to 8% are common'.*

The footnote reference for the 3-8 per cent range cited by Impaq referred to the following (at footnote 17, p38):

> *'Eg: Aust Financial Review – 10 March 2010 – Profits 2010, Page 12. Major service companies EBIT margins between 3% and 8%. Some instances are: United Group Limited, which provides services across several industries including electricity, have historically achieved net profit margins of about 5%. Refer UGL annual reports. Norfolk (which includes O'Donnel Griffin electrical contracting) has an EBIT margin of 3% in recent years. Downer EDI 5%, Leightons 7.5%)'.*

The margin used by Impaq in the calculation of labour costs in this report was 3-8 per cent, which was over and **above** the allowance made for overheads.

overheads and a return of capital invested in physical assets. Since the sample of entities relied upon by both NERA and Impaq in their respective studies was limited to those contractors that use a relatively low proportion of physical assets in the derivation of revenue, the margins can also be assumed to be well in excess of any return on capital that might otherwise be required for any physical assets used by the contractor.

The results of both NERA's and Impaq's studies demonstrate that contractors providing analogous services to those provided by CHED Services and PNS under the Corporate Services Agreement and the Network Services Agreement in contestable markets consistently earn margins in excess of the amounts that would be warranted for the factors identified by the AER as being 'legitimate' bases for payment of a margin. The results of these studies therefore suggest that either the AER's proposition does not hold in practice, or that there are other factors, such as differences in the relative efficiency of contractors, supporting the payment of a margin above the contractor's directly incurred costs, overheads and a return on and of capital. Either way, the studies provide unequivocal evidence that contractors providing analogous services to those provided by CHED Services and PNS under the Corporate Services Agreement and the Network Services Agreement in contestable markets earn margins in excess of overheads and a return on and of capital invested in physical assets.

Against this background, it is salient to revisit the conclusions of the Tribunal in *Application by Optus Mobile Pty Limited and Optus Networks Pty Limited*[253] discussed above and in Appendix 5.1 to this Revised Regulatory Proposal. Consistent with the results of the NERA and Impaq Consulting studies, which demonstrate that contractors consistently earn margins in excess of the amounts that would be warranted for the factors identified by the AER as being 'legitimate' bases for payment of a margin, the Tribunal concluded that, in a workably competitive market, a service provider may gain a competitive advantage by having access to economies of scale and scope by reason of its ownership and operation of other networks in addition to the regulated network. On this basis, the Tribunal concluded that the stand-alone, in-house cost of service provision is the cost benchmark that best reflects the pricing outcomes that would prevail in a workably competitive market.

It necessarily follows that the expenditure incurred by a DNSP under outsourcing arrangements that fail the 'presumption threshold' that is allowed by the AER will be lower than the expenditure that would be incurred by the DNSP if it acquired the outsourced services in a workably competitive market through an open, competitive tender process. This is further illustrated in section 5.5.2 below by

[253] [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].

reference to the margins payable by parties other than CitiPower and Powercor Australia to PNS for the provision of analogous services in such markets.

Another flaw in the AER's application of theory regarding pricing outcomes in workably competitive markets is that, in using the term 'margin', the AER equates the contractor's actual costs (both direct and indirect costs) with the 'full economic cost' of delivering the service. In so doing, the AER ignores the potential for the 'full economic cost' to include factors other than a contractor's direct and indirect actual costs, which factors render it possible in a workably competitive market that a margin in excess of the direct and indirect costs may be maintained over the longer run.

Finally, CitiPower finds it somewhat peculiar that the AER applies theory regarding pricing outcomes in workably competitive markets in its second stage assessment but has **not** sought to apply the same line of logic to those contracts that are deemed to pass the 'presumption threshold'. In particular, the AER has not sought to exclude any margin in excess of overheads and a return on and of capital invested in physical assets from the expenditure forecast to be incurred under these contracts. If the AER were genuinely of the view that, in a workably competitive market, a contractor would not be able to earn a margin referable to scale, scope or other efficiencies realised by the contractor for periods exceeding the duration of a 5 year regulatory control period, it would have excluded from DNSPs' expenditure forecasts any margins in excess of overheads and a return on and of capital invested in physical assets that are payable under those outsourcing arrangements that pass the 'presumption threshold'.

5.5.1.3 No recognition of potential efficiency of outsourcing arrangements and creation of perverse incentives

On the spectrum of possible counterfactuals that could be employed when assessing expenditure forecast to be incurred under an outsourcing agreement that fails the 'presumption threshold', the position taken by the AER is the most stringent. That is, it assumes that **all** of the efficiencies available to the contractor, including those derived from the provision of regulated and unregulated services to other related entities and third parties, are equally available to the DNSP and should therefore be passed on to consumers.

The AER's adoption of this counterfactual means there is **no** prospect whatsoever for outsourcing contracts that are deemed to fail the presumption threshold to be a more efficient means of delivering a service than in-house provision. This is in marked contrast to the ESCV's recognition, in the GAAR, that outsourcing arrangements that cannot be presumed to be efficient (i.e. that fail the 'presumption threshold') may nonetheless be an efficient means of service delivery.

In CitiPower's opinion it is not sufficient to simply **assume** that, in circumstances where a DNSP is found to have an **incentive** to agree to non arm's length terms, the DNSP actually **acted** upon that incentive. Rather, a more detailed inquiry of the nature described by the ESCV in the GAAR should be undertaken to determine whether the incentive was actually acted upon and resulted in the payment of a price that exceeds that which would otherwise have been incurred if the services had been provided in-house.

CitiPower understands that in developing its framework, the AER has had regard to the work undertaken by the ESCV in the context of both its 2006-10 EDPR and the GAAR and has also considered the submissions made by a number of economic consultants during the ESCV's review process for making the GAAR.[254] It would also appear that the AER has had regard to the principles referred to in the Jemena Gas Access Draft Decision but **not** to the actual decision to allow a margin in the Jemena Gas Access Final Decision.

The framework developed by the ESCV in the context of the GAAR had its genesis in the ESCV's 2006-10 EDPR, although the final framework used by the ESCV in the GAAR differed in a number of fundamental ways from the framework applied in the 2006-10 EDPR (see Figure 5.2 below). One of the more significant changes to be made by the ESCV in the GAAR was to recognise that, while the circumstances surrounding the entry into the contract may mean that price payable under a contract could not be **presumed** efficient, a more detailed enquiry was required to determine whether the **incentive** a service provider may have had to agree to non arm's length terms had actually been acted upon.

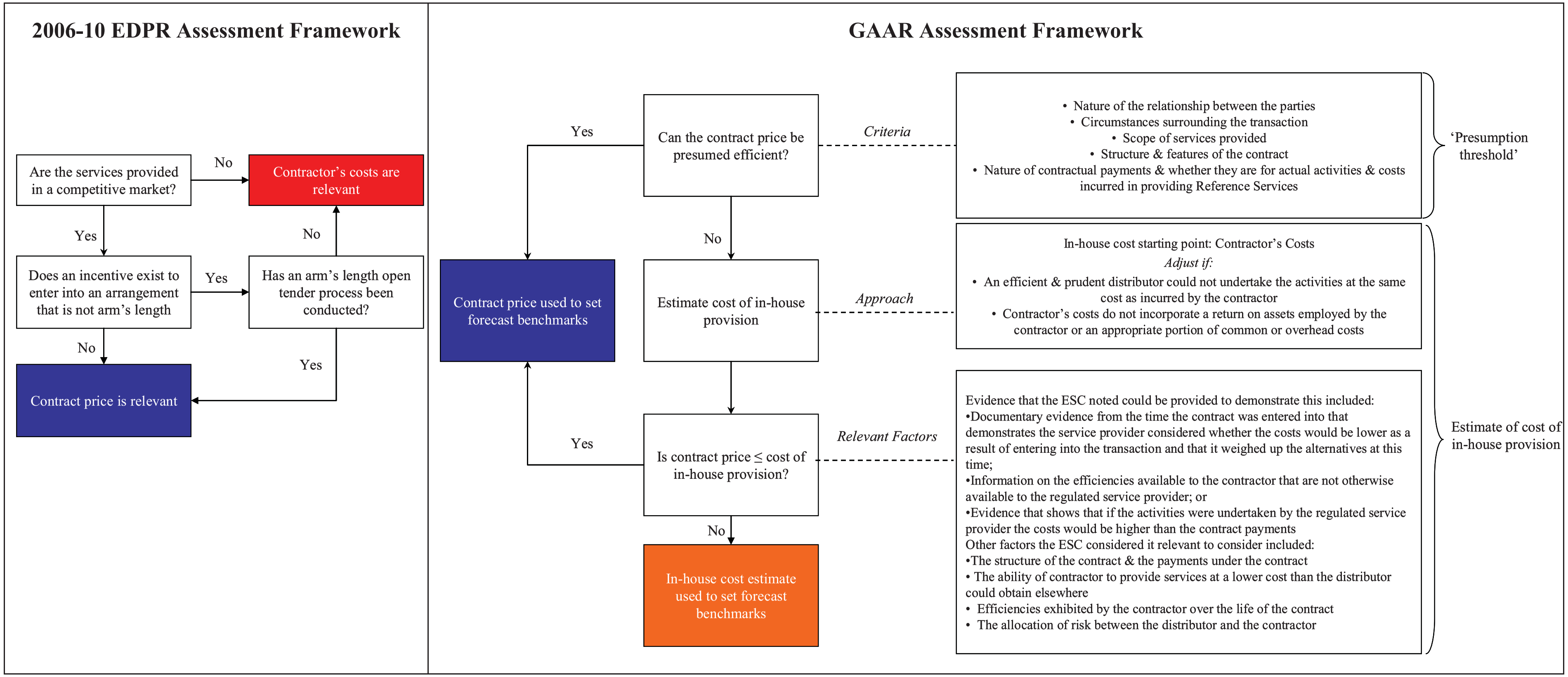
The framework adopted by the ESCV in the GAAR was therefore modified to allow for the potential for the **contract price** to be used where it could be demonstrated that the contract price was **lower** than the cost of in-house provision.[255] While the starting point for estimating the in-house cost of provision under the ESCV's framework was contractor's costs, the ESCV acknowledged that consideration would also need to be given to the following factors:[256]

- whether the contractor was able to achieve economies of scale, scope and other efficiencies (such as 'know-how') **not otherwise available to the in-house provider**;
- whether the actual costs incurred by the contractor incorporated a return on the assets employed by the contractor and/or an appropriate portion of common costs;
- efficiencies on the part of the contractor over the life of the contract; and

[254] AER, Draft Determination, pp162-8.
[255] ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p43.
[256] ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), pp59-60.

- the manner in which the contact allocates risk between the regulated service provider and the contractor.

Figure 5.2: ESCV's Assessment Frameworks



Source:

ESCV, Electricity Distribution Price Review 2006-10 Final Decision: Notice of Errata, 23 November 2005 (Attachment 100 to this Revised Regulatory Proposal).

ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), pp43-153.

The position taken by the ESCV on this issue is reflected in the following statement:[257]

> *'In looking at the actual costs incurred by the contractor in undertaking the contracted activities, the Commission is not adopting the position that only the contractor's actual costs form a reasonable basis for the benchmark of prudent and efficient costs. The Commission accepts that, consistent with the views of both NERA and ACG, if over the relevant time horizon, the contractor incurs lower expected costs relative to providing the services in-house then this is a prudent and efficient outcome. Provided the overall contract payments do not exceed the amount that would have been incurred by the distributor undertaking the activity itself, the full contract amount would represent an efficient level of expenditure.'*

The alternative types of evidence that the ESCV considered relevant to the assessment of whether the contract price was lower than the costs the regulated service provider would incur if it undertook the activities itself are described in the following statement:[258]

> *'There are various ways a distributor may seek to demonstrate that the costs it incurs under the outsourcing arrangements are lower than the costs that it would likely incur if it undertook the activities itself. One way to do this would be to produce evidence that it considered this factor when it entered into the contract and weighed up the alternatives before entering into the contract. Another way is to identify economies of scale, scope or other efficiencies that are available to the contractor that are not available to it. Another way is to provide evidence that shows that if it undertook the activities itself its costs would be higher than the contract payments.'*

While the AER appears to have drawn heavily upon the work on the presumption threshold undertaken in the context of the GAAR, it has essentially gone back to the position adopted by the ESCV in its 2006-10 EDPR in respect of the stage two assessment required where a contract fails the presumption threshold and assumed that the contractor's costs (including a share of overheads and a return on and of physical assets) should be used as the basis for determining forecast opex and capex.

For the reasons set above, CitiPower disagrees with the position taken by the AER on this issue and notes that if it were employed then it would create a perverse incentive for DNSPs to bring the operations back in-house even if the price payable to its contractor is less than the cost it would incur if it were to provide the service in-house.

[257] ESCV, Draft GAAR, Chapter 5 (Attachment 101 to this Revised Regulatory Proposal), p55.
[258] ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p52.

5.5.1.4 Inconsistency with previous regulatory decisions

The position taken by the AER in the Draft Determination on the benchmark or counterfactual that should be applied when assessing opex and capex forecast to be incurred under outsourcing agreements that fail the 'presumption threshold', including in particular the margins payable thereunder, is materially different from the position taken by the AER and the ESCV in previous regulatory decisions.

The AER's position in the Draft Determination on the benchmark or counterfactual is inconsistent with the position taken by the AER in both:

- the South Australian Draft Determination. In this Draft Determination, the AER considered the costs incurred by ETSA under its commercial contracts with CHED Services for the provision of call centre, FRC and FRC systems support services and noted that it supported the conclusion reached by its own consultant, PB, that *'outsourcing these services results in lower costs than providing the services in-house on a stand alone basis'*.[259] The counterfactual adopted by the AER in this case is directly at odds with its current contention that the stand alone counterfactual is not the appropriate counterfactual to apply when assessing forecast opex and capex; and
- the Jemena Gas Access Final Decision. Released one week after the Draft Determination, the Jemena Gas Access Final Decision allowed a commercial-in-confidence margin to be included in the derivation of Jemena Gas' forecast opex and capex.[260] Since this Final Decision has been heavily redacted it is not possible to determine whether the margin allowed by the AER is the same as that which was proposed by Jemena Gas. However, it is apparent from the AER's discussion of this issue that it did not assess whether the margin reflected the amount required by the contractor to recover a reasonable share of its overheads, a return on and of capital invested in physical assets and/or an allowance for asymmetric risks.[261] To the contrary, the AER's decision on the margin that would satisfy the relevant criteria in the National Gas Rules appears to have been made on the basis of benchmark studies:[262]

  > *'The AER considers that the [c-i-c] is consistent with the benchmarking evidence...'*

As discussed in section 5.5.1.3 above, the AER's position in the Draft Determination on the benchmark or counterfactual that should be applied when assessing opex and capex forecast to be incurred under outsourcing agreements that fail the 'presumption threshold' represents a significant departure from the ESCV's position in the GAAR.

[259] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p206.
[260] AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), pp. 56-7 and 273.
[261] AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), pp. 56-7 and 267-273.
[262] AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), p270.

5.5.1.5 Alternate assessment framework

There are, in CitiPower's view, a number of fundamental shortcomings with the second stage assessment undertaken pursuant to the framework developed by the AER and the approach that it has employed when assessing those contracts that are deemed to fail the presumption threshold.

To address these shortcomings, CitiPower suggests that the framework developed by the AER be amended to bring it into line with the approach taken by the ESCV in the GAAR. Specifically, Stage 2B of the AER's framework should be amended to recognise the potential for the price (including an explicit or an implicit margin) payable under a contract that fails the 'presumption threshold' to comply with the opex and capex criteria contained in clauses 6.5.6(c) and 6.5.7(c) of the Rules, where it can be demonstrated that the contract price is less than or equal to the in-house cost of provision, where the in-house cost of provision is measured by reference to the stand-alone counterfactual.

The framework should also provide guidance to a DNSP on the types of evidence that may satisfy the AER that the price(s) payable under its outsourcing contract(s) are lower than the in-house cost of provision and, thus, reasonably reflect the opex and capex criteria. In keeping with the position taken by the ESCV on this issue,[263] CitiPower considers that it should suffice to satisfy the AER for a DNSP to submit evidence of one or more of the following types:

- documentary evidence from the time the contract was entered into that demonstrates that the DNSP considered whether the contract would lower its overall costs and that it weighed up the alternatives before entering into the contract;
- information on the economies of scale, scope and/or other efficiencies that would be available to the contractor that would not otherwise be available to the DNSP; or
- evidence that demonstrates that if the DNSP undertook the activities itself the costs would be higher than the contract payments.

Where a DNSP is able to demonstrate that the contract price is lower than the in-house cost of provision, then the contract price should be accepted as representing the appropriate basis for determining forecast opex and capex subject to the following two caveats, which also apply to those contracts that pass the 'presumption threshold':

- the contract price relates wholly to the provision of the regulated service; and
- there is no double counting of costs or risks between the contract price and the DNSP's building block proposal.

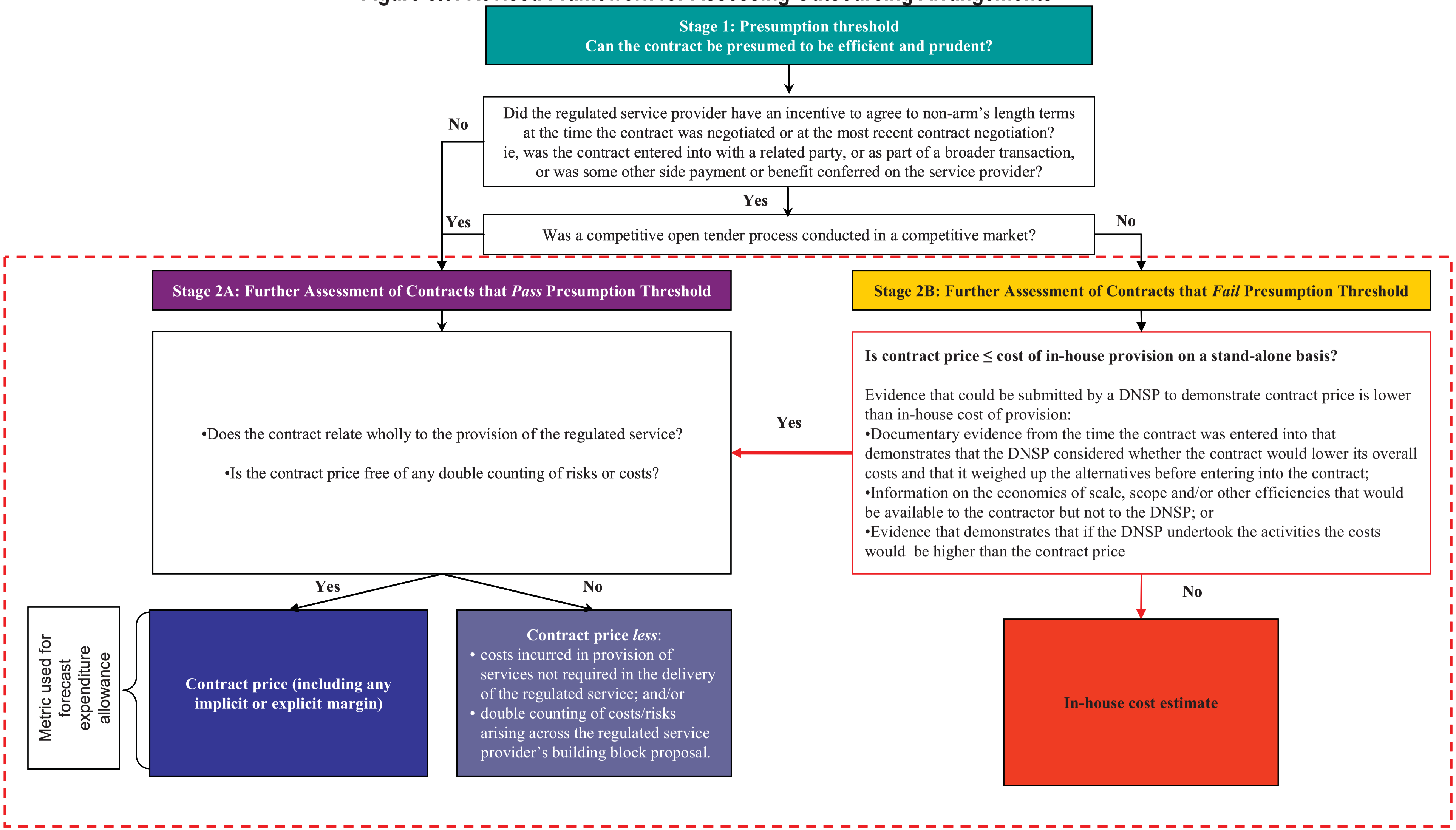
[263] ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p52.

In other words the contract should move from Stage 2B of the AER's framework to Stage 2A of the framework.

In those circumstances where a DNSP is unable to demonstrate that the contract price is lower than the in-house cost of provision, the AER should utilise the in-house cost estimate in the derivation of forecast opex and capex.

The modifications that CitiPower submits should be made to the AER's framework are set out in Figure 5.3 below.

Figure 5.3: Revised Framework for Assessing Outsourcing Arrangements



Other factors that CitiPower considers could inform a regulator's decision on whether the expenditure incurred under a contract that is deemed to fail the presumption threshold nonetheless reasonably reflects the opex and capex criteria contained in clauses 6.5.6(c) and 6.5.7(c) of the Rules, which were also identified by the ESCV as being relevant to the consideration, include:

- an assessment of the contract with particular emphasis placed on:[264]
    - the level of control accorded to the DNSP over the expenditure incurred by the contractor and other governance arrangements contained in the contract;
    - the extent to which the contract accords the contractor with an incentive to lower costs and to pass those reduced costs on to the DNSP; and
    - the risks accorded to the contractor under the contract; and
- comparative benchmark analysis.[265]

CitiPower understands that the AER has some concerns about benchmark studies and the extent to which they can be relied upon to demonstrate compliance with the forecast opex and capex criteria contained in the Rules. While CitiPower agrees that some care must be taken with benchmark studies, it believes that they still have a role to play particularly when they form part of a broader submission that demonstrates that the price payable under the contract does not exceed the level that would be incurred if the services were provided in-house.

5.5.2 Corporate Services Agreement with CHED Services and Network Services Agreement with PNS

CitiPower disagrees with the AER's assessment of the margins payable to CHED Services under the Corporate Services Agreement and PNS under the Network Services Agreement.

CitiPower is of the opinion that the price payable under both the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, including the implied margins, should be accepted by the AER as being consistent with the opex and capex criteria contained in the Rules and used in both the derivation of forecast opex and capex for the 2011-15 regulatory control period and the calculation of EBSS carry over amounts in this period.

A primary reason for the AER's exclusion of the margins payable under the Corporate Services Agreement and the Network Services Agreement with PNS from CitiPower's expenditure forecasts was its conclusion that the adoption by CitiPower and Powercor Australia of their current service model was imprudent, in their respective circumstances.[266] The AER reasoned that:[267]

> *'[P]rior to these services being provided by CHED Services and PNS, these services were provided by Powercor to both itself and CitiPower. ... The AER is not satisfied that the move to a business model where it now pays a profit margin to a related party*

[264] ESC, Draft GAAR, Chapter 5 (Attachment 101 to this Revised Regulatory Proposal), p54.
[265] ESC, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p55.
[266] AER, Draft Determination, p192 and Appendix H at pp26 and 29.
[267] AER, Draft Determination, p192.

(a cost it did not previously incur when providing the same services to itself) reflects the actions of a prudent operator in Powercor's circumstances.'

While not expressly stated in the Draft Determination, it would appear that the AER would consider CitiPower's decision to adopt its current service model, under which it pays a margin to CHED Services and PNS, as imprudent for analogous reasons.

CitiPower wishes to address this AER reasoning at the outset. CitiPower refutes the AER's suggestion that the decision by CitiPower and Powercor Australia to adopt their current service model, under which it pays a margin to CHED Services and PNS, was imprudent. CitiPower maintains that, to the contrary, the decision to adopt the current service model was prudent at the time of that decision and remains prudent if assessed with the benefit of hindsight. This is because:

- As discussed in the Initial Regulatory Proposal, a key rationale for the decision to adopt the current service model was to enable CitiPower and Powercor Australia to better focus on their long term asset ownership and performance.[268] In addition, other benefits of the current service model that were a part of the rationale for the decision to adopt that service model include:
  - the creation of increased incentives to pursue efficiency gains;
  - the greater potential for business growth/expansion including in particular through the provision of services to other entities within the group and third parties;
  - improved regulatory outcomes through the more cost-efficient provision of back office services than was achievable by Powercor Australia providing those services to itself and CitiPower;
  - greater potential for an improvement in back office service levels and performance; and
  - improved cost allocation and an associated reduction in the potential for the attribution of profits generated by the group through the provision of unregulated services to the provision of regulated services.[269]
- As intended at the time of the decision to adopt the current service model, the current service model has facilitated the provision of services to other entities within the group, notably ETSA where this is efficient for it, and the associated realisation of additional scale and scope efficiencies not available under the previous service model.

[268] Initial Regulatory Proposal, p357.

[269] The following extracts from Board papers and minutes of the Board of CitiPower and Powercor Australia, and minutes of the Executive Committee of CitiPower and Powercor Australia, disclose that this was the rationale for establishment of the current service model; Extract of CitiPower Board Minutes, 24 August 2004 (Attachment 111 to this Revised Regulatory Proposal); Extract of Powercor Australia Board Minutes, 24 August 2004 (Attachment 112 to this Revised Regulatory Proposal); Extract of CitiPower Executive Committee Minutes, 10 December 2004 (Attachment 113 to this Revised Regulatory Proposal); Extract of Powercor Australia Executive Committee Minutes, 10 December 2004 (Attachment 114 to this Revised Regulatory Proposal); Presentation given by Shane Breheny, Chief Executive Officer CitiPower and Powercor Australia, and Julie Williams, Chief Financial Officer CitiPower and Powercor Australia, to Executive Committees of CitiPower and Powercor Australia at meeting of 10 December 2004 (Attachment 115 to this Revised Regulatory Proposal); Extract of CitiPower Executive Committee Minutes, 27 January 2005 (Attachment 116 to this Revised Regulatory Proposal); Extract of Powercor Australia Executive Committee Minutes, 27 January 2005 (Attachment 117 to this Revised Regulatory Proposal); CitiPower Board Paper, Related Party Contract Recommendations, 17 November 2006 (Attachment 118 to this Revised Regulatory Proposal); Powercor Australia Board Paper, Related Party Contract Recommendations, 17 November 2006 (Attachment 119 to this Revised Regulatory Proposal).

Approximately [redacted] per cent of CHED Services' revenue in 2009 was generated from the provision of services to ETSA. A report prepared for ETSA by SMS Consulting that was submitted to the AER by ETSA in the context of the South Australian Final Determination identifies the potential efficiencies associated with this provision of services to ETSA by CHED Services.[270]

- As intended at the time of the decision to adopt the current service model, the adoption of this model has enabled the group to expand its business activities to include the provision of unregulated services to other parties. As discussed in section 5.5.2.3 below, PNS, in particular, generated [redacted] per cent of its revenue in 2009 from the provision of services to parties other than CitiPower and Powercor Australia. In addition, PNS continues to expand this aspect of its business activities. As a result, the current service model has also facilitated the realisation, and will continue to facilitate the future realisation, of additional scale and scope efficiencies not available under the previous service model, through the provision of services by CHED Services and PNS to other parties.

In any event, as discussed in section 5.5.1.1 above, the Rules require the AER to adopt the stand alone counterfactual when assessing the extent to which CitiPower and Powercor Australia can access the same efficiencies as those that are available to the contractor. The AER is required to disregard any scale, scope and other efficiencies accruing by reason of the common ownership and operation of the CitiPower and Powercor Australia distribution networks in establishing benchmark efficient and prudent expenditure against which to assess whether their expenditure forecasts satisfy the opex and capex criteria. This would be the case, even if CitiPower and Powercor Australia were still employing their previous service model, pursuant to which Powercor Australia provided the relevant services to itself and CitiPower.

In section 5.5.1 above, CitiPower established that:

- the Rules permit the AER to substitute alternative expenditure forecasts only where CitiPower's proposed expenditure is not efficient;
- the AER should adopt an assessment framework pursuant to which it undertakes a more detailed inquiry, in keeping with the approach adopted by the ESCV in the context of the GAAR, to determine whether the contract price exceeds the costs that would have been incurred if the services were provided in-house on a stand alone basis; and
- even if the AER were to adopt a more stringent counterfactual than the stand-alone, in-house cost of service provision (which CitiPower does **not** concede is permissible under the Rules) then the AER should **not** take into account the efficiencies derived by the contractor from the provision of unregulated services or, at a minimum, the provision of services to third parties when assessing a DNSP's forecast expenditure under an outsourcing arrangement that fails the 'presumption threshold'.

[270] SMS Consulting, Review of CHED Services' forecast for FRC systems support, 25 February 2009 [commercial in confidence] provided to the AER by ETSA as Attachment F.11 to ETSA's Revised Regulatory Proposal 2011-15 dated 14 January 2010 (Attachment 107 to this Revised Regulatory Proposal). In this report, SMS Consulting considered whether CHED Services could provide the FRC systems required by ETSA at lower cost than it could achieve if it were to provide the services in-house or outsource the services to another party. SMS Consulting concluded that retaining CHED Services was the best option and in doing so referred to the benefit that ETSA would obtain because it would be able to retain *'synergies with CitiPower and Powercor with shared support services, infrastructure and software licences support fees'*.

On the basis of the foregoing, CitiPower maintains that the AER should not exclude the implied margins payable under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS from its forecast expenditure for 2011-15 because:

- benchmarking analysis demonstrates that CitiPower's opex inclusive of any expenditure under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, including implied margins, is efficiently incurred;
- the application of the modified framework discussed in section 5.5.1.5 above establishes that the price payable under both the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, including the implied margins, should be accepted by the AER as reasonably reflecting the opex and capex criteria contained in the Rules; and
- the efficiencies available to PNS include efficiencies derived from the provision of unregulated services and services to third parties which, as noted above, should not be taken into account by the AER when assessing a DNSP's forecast expenditure under an outsourcing arrangement that fails the 'presumption threshold'.

CitiPower elaborates on each of these contentions in greater detail, in turn, below.

In addition, CitiPower responds to the AER's conclusion, in assessing the margins payable under the Corporate Services Agreement and the Network Services Agreement, that the Ernst & Young reports commissioned by CitiPower and Powercor Australia and used to determine the initial margins payable under those Agreements[271] are of no relevance because differences in the objectives underpinning the tax and economic regulatory regimes meant that it could not be *'assumed that practices which are appropriate in a tax context are always appropriate in an economic regulatory context'*[272]. Contrary to the AER's conclusion in the Draft Determination, CitiPower maintains that the reports prepared by Ernst & Young on arm's length transfer prices are relevant and establish that the margins payable by it under the Corporate Services Agreement and the Network Services Agreement reflect the margins that would be expected to be agreed to by parties operating on an arm's length basis.

[271] Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment C0049 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Customer Services (Excluding Metering), 20 November 2006 (Attachment C0050 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services), 20 November 2006 (Attachment C0051 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 21 May 2009 (Attachment C0052 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services, 30 November 2006 (Attachment C0048 to the Initial Regulatory Proposal). As discussed in the Initial Regulatory Proposal (at p350), in the May 2009 report by Ernst & Young, it updates the benchmark IT margin previously provided in its November 2006 report in respect of IT services and indicates that there has been little movement in the benchmark IT margin over the intervening period.

[272] AER, Draft Determination, pp187-8 and Appendix H at pp26 and 29.

5.5.2.1 Efficiency of expenditure forecasts inclusive of expenditure under Corporate Services Agreement and Network Services Agreement

CitiPower maintains that the AER must accept its forecast opex under the Corporate Services Agreement with CHED Services, including the implied margins, without adjustment because:

- as discussed in section 5.5.1.1 above and Appendix 5.1 to this Revised Regulatory Proposal, the opex criteria, properly construed, do not permit the AER to reduce a DNSP's total opex forecasts, for example to exclude margins under outsourcing arrangements, below the efficient costs of achieving the opex objectives;
- in deciding whether it is satisfied that CitiPower's total opex forecast reasonably reflects the opex criteria, clause 6.5.6(e)(4) of the Rules provides that the AER must have regard to benchmark opex that would be incurred by an efficient DNSP over the regulatory control period; and
- benchmarking analysis establishes that CitiPower's forecast opex for 2011-15 inclusive of any expenditure under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, including the implied margins, is efficiently incurred.

This section 5.5.2.1 discusses the relevant benchmarking analysis.

Efficiency of total opex forecast

CitiPower and Powercor Australia engaged NERA to carry out a benchmarking exercise and to assess their relative efficiency *vis-à-vis* 11 other DNSPs operating in the NEM[273] and Western Australia. In so doing, NERA assessed the relative efficiency of:

- the forecast opex of CitiPower, Powercor Australia and other Victorian DNSPs for 2011-15 set out in their initial regulatory proposals of November 2009; and
- the opex allowance approved by the relevant regulator for DNSPs in other jurisdictions in their most recent distribution regulatory reviews.[274]

To assess the relative efficiency of CitiPower and Powercor Australia, NERA conducted a regression analysis similar in nature to the 'top down' analysis undertaken by the Ofgem to regulated distributors in the United Kingdom in its most recent price review. NERA also examined the relative performance of CitiPower and Powercor Australia using the ratios identified by the AER as being relevant in the context of the South Australian and Queensland Final Determinations and the Draft Determination.[275]

The results of this study are set out in a report entitled 'Review of Operating Expenditure Efficiency'. In summary, the results of this study indicate that:

[273] The DNSPs included in this study include Energex, ETSA, Ergon, Jemena, UED, Country Energy, SP AusNet, Western Power, Integral Energy, Energy Australia and ActewAGL.

[274] NERA, Review of Operating Expenditure Efficiency, July 2010 (Attachment 102 to this Revised Regulatory Proposal), pp5-6 and opex column in Table A.3 on pp26-30.

[275] The ratios considered by NERA were opex per customer, opex per GWh of energy consumed, Opex per MW of maximum demand, opex per km, opex as a percentage of RAB.

- using the top-down approach CitiPower was found to be the **most** efficient of the 13 DNSPs examined by NERA;[276] and
- using the opex ratios previously employed by the AER, CitiPower was ranked as the most efficient in terms of opex per customer, opex per GWh, opex per MW and opex as a percentage of RAB and the ninth most efficient for opex per km. The latter of these rankings is not altogether surprising given the nature of CitiPower's distribution network.[277]

The results of this study demonstrate that, on a comparison of their opex forecasts for 2011-15 set out in their Initial Regulatory Proposals to the opex allowed for DNSPs in other jurisdictions in recent regulatory determinations, CitiPower and Powercor Australia are the most efficient DNSPs in Australia.

Efficiency of total capex forecast

Benchmarking capex has its difficulties. As the AER observed in its South Australian Final Determination:[278]

> *'Benchmarking total capex, especially over short periods of time, can be difficult, where the lumpiness of capex programs can impact on results. Firm-specific factors that are unaccounted for in a model may appear as inefficiency where this is not the case. Non-system capex is generally less lumpy and therefore better suited to benchmarking.*
>
> *Different licensing requirements can make a large difference in a business' required system capex spend. For example, mandatory system security standards will vary from state to state. There are also differences in whether businesses buy or lease assets, and different in balance dates, all of which can make benchmarking more problematic.'*

Nevertheless, CitiPower provides to the AER the results of a survey of market prices conducted by SKM, which are contained in a report entitled 'SKM Market Price Survey #4 – Results of a Survey for CitiPower'. As part of the survey, SKM collected information about the market prices (including all material, labour, transport and overhead costs) for a sample range of eight typical distribution utility capital works unit rates. For the eight categories of capital works that were the subject of the survey, SKM determined a deemed market price (the mean of the market prices collected). Given the nature of CitiPower's assets, CitiPower was only able to provide prices for five of the eight categories surveyed by SKM. SKM's comparison of the deemed market price with the price submitted by CitiPower was therefore limited to five categories. The results of the survey conducted by SKM are summarised in confidential Table 5.1.

As the results in this Table demonstrate, the prices submitted by CitiPower were higher than the deemed market price across each of the five categories relevant to CitiPower.[279] The

[276] NERA, Review of Operating Expenditure Efficiency, July 2010 (Attachment 102 to this Revised Regulatory Proposal), pp20-21.
[277] NERA, Review of Operating Expenditure Efficiency, July 2010 (Attachment 102 to this Revised Regulatory Proposal), Table C.1.
[278] AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), pp368-9.

results of this survey are not altogether surprising given the unique nature of CitiPower's network and the fact that there are no other DNSPs in Australia operating in conditions that are directly comparable to those faced by CitiPower. This point was made clear by SKM in its discussion of the survey results:[280]

> *'In the case of CitiPower there is not another participant that could be considered a close match in terms of size or customer mix. CitiPower is the only distributor to have a franchise area that is predominantly CBD or urban, with little or no rural networks.*
>
> …
>
> *While location is not expected to affect raw material costs (Part 1), a predominantly CBD and Urban network such as CitiPower is likely to face higher costs for items such as traffic management, a greater proportion of hard footpaths requiring reinstatement, and congestion for the capital and maintenance activities considered in Parts 2 and 3 of this report. Without another DNSP participant that offers a direct comparison, care needs to be taken that the results of this survey are not misinterpreted. An allowance needs to be made for the inherently higher costs for capex and opex activities in the CitiPower franchise compared to the average for other participants.'*

In the absence of any real comparators to benchmark its performance against, CitiPower is of the view that no real weight can be placed on the results of this survey.

[279] SKM, SKM Market Price Survey #4 – Results of Survey for CitiPower, 6 July 2010 (Attachment 103 to this Revised Regulatory Proposal), piii.

[280] SKM, SKM Market Price Survey #4 – Results of Survey for CitiPower, 6 July 2010 (Attachment 103 to this Revised Regulatory Proposal), pv.

Capex activity	Deemed market price	CitiPower Australia's submitted price	Difference
Install 11kV / 22kV and LV underground cable in urban area	$324,895	$355,529	9.4%
Install 11kV / 22kV underground cable in rural area	$144,485	n.a.	n.a.
Construct 1km of 11kV / 22kV overhead line (wood pole, medium conductor) in urban area	$73,749	$74,945	1.6%
Construct 1km of 11kV / 22kV overhead line (concrete pole, medium conductor) in urban area	$95,742	$102,773	7.3%
Construct 1km of 11kV / 22kV overhead line (wood pole, medium conductor) in rural / regional area	$42,195	n.a.	n.a.
Construct 1km of 11kV / 22kV overhead line (concrete pole, medium conductor) in rural / regional area	$45,301	n.a.	n.a.
Construct 22kV / 415V or 11kV / 415V, 3 phrase, 300kVA pole mounted substation (urban environment)	$31,316	$41,230	31.7%
Install 500kVA, 3 phase, 11kV / 22kV – 415V kiosk or pad mounted substation	$73,379	$86,870	18.4%

Table 5.1 Summary of SKM results for unit rate prices for capital works

5.5.2.2 Application of modified assessment framework to Corporate Services Agreement and Network Services Agreement

CitiPower's Initial Regulatory Proposal contained a considerable amount of information about each of the outsourcing arrangements that it has in place with parties that could be viewed as being 'related' to CitiPower at the time they were entered into. While CitiPower accepts the AER's conclusion that the Agreements it has in place with CHED Services and PNS cannot be **presumed** to be consistent with the opex and capex criteria, it does **not** agree with either:

- the approach employed by the AER when considering the relevance of the price payable under these agreements; or
- its decision to exclude the margins payable under these Agreements from the derivation of forecast opex and capex and the calculation of the EBSS carry over amounts for the 2011-15 regulatory control period.

In short, CitiPower does not agree that it is sufficient for the AER to simply presume that because CitiPower may have had an incentive to agree to non arm's length terms that the Agreements it entered into were actually non arm's length.

To the contrary, CitiPower is of the opinion that a more detailed inquiry must be undertaken to determine whether the contract price exceeds the costs that would have been incurred if the services were provided in-house on a stand alone basis (see section 5.5.1.4). In keeping with the approach adopted by the ESCV in the context of the GAAR, such an assessment should be informed by:

- evidence that demonstrates that the price payable under the contract is lower than the cost of in-house provision;
- an assessment of the non-price terms and conditions contained in the contract to determine whether these are consistent with what one would expect to observe in an arm's length contract; and
- comparative benchmark analysis.

The remainder of this section 5.5.2.2 applies the framework that CitiPower considers should be employed when assessing these types of arrangements (see Figure 5.3) to the Corporate Services Agreement and the Network Services Agreement. Commencing with an overview of the two Agreements, this section then sets out:

- evidence that demonstrates that the prices payable under these two Agreements are lower than the cost of in-house provision;
- the results of an assessment of the non-price terms and conditions; and
- the results of an assessment of incentives provided under the two Agreements.

Section 5.5.2.1 above discusses the assessment of the performance of CitiPower relative to its peers and, accordingly, this will not be revisited in this section 5.5.2.2. Suffice to say that, as discussed above, this assessment demonstrates that CitiPower's forecast opex inclusive of any implied margins incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, is efficiently incurred.

Overview of Corporate Services Agreement with CHED Services

Under the terms of the Corporate Services Agreement, CHED Services provides CitiPower with specialist corporate services including: the Chief Executive Officer; Finance; the Company Secretary and Legal; Human Resources; Corporate Affairs; Regulation; Customer Services; Information Technology; and Office Administration.

The original Corporate Services Agreement was entered into by CitiPower with CHED Services in 2005 and had a term of just one year. The Agreement was renewed in 2006 and 2007, in each instance for a one year period, and in January 2008 the parties entered into the current Corporate Services Agreement, which operates over a three year period from 1 January 2008 through to 31 December 2010. The current Agreement has been used as the basis for the estimation of CitiPower's forecast expenditure for 2011-15.

Prior to entering into the 2007 and 2008-10 Agreements, CitiPower's Board established strict governance arrangements for the engagement of related parties.[281] The principles established by the Board were the following:

- related party transactions are supported by contracts;
- contracts are commercial and arm's length, which includes: ensuring prices are based on market prices or comparable prices to unrelated parties or 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' that are required by service recipients; and a reduction in fees for excessive, or enduring, poor performance;
- independent verification of arm's length nature of contracts;
- transactions comply with relevant laws; and
- transactions comply with undertakings to bond holders, banks, insurers and rating agencies.

In keeping with these principles, CitiPower and CHED Services have agreed to terms and conditions (including price) that are in line with those that would be expected to have been agreed through an arm's length negotiation process. The arm's length nature of the Agreement has been independently verified by KPMG.[282]

The pricing structure adopted in this Agreement consists of a fixed fee and provision has been made for this fee to be escalated in 2009 and 2010 using the change in the CPI. The fixed charge in 2008 was based on forecast efficient costs plus a commercial margin. The margins used in the derivation of charges payable under the Agreement was based on the recommendations contained in a series of reports that were prepared by Ernst & Young for CitiPower and Powercor Australia in 2006.[283] There are no other incentive payments or overheads payable by CitiPower under this Agreement.

Overview of Network Services Agreement with PNS

In 2008, CitiPower entered into the Network Services Agreement with PNS. Under the terms of this Agreement, PNS provides CitiPower with various services including: customer and connection services; asset replacement maintenance services; asset performance (fault) services; and network development.

In keeping with the related party governance arrangements put in place by the CitiPower Board in 2006 discussed above, CitiPower and PNS have agreed to terms and conditions

[281] Initial Regulatory Proposal, p355.
[282] KPMG, Powercor Australia Limited, Consideration of the arms length nature of the Shared Service Arrangements, December 2007 (Attachment C0092 to the Initial Regulatory Proposal), p1.
[283] Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment C0049 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Customer Services (Excluding Metering), 20 November 2006 (Attachment C0050 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services), 20 November 2006 (Attachment C0051 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 21 May 2009 (Attachment C0052 to the Initial Regulatory Proposal). As discussed in the Initial Regulatory Proposal (at p350), in the May 2009 report by Ernst & Young, it updates the benchmark IT margin previously provided in its November 2006 report in respect of IT services and indicates that there has been little movement in the benchmark IT margin over the intervening period.

(including price) that are in line with those that would be expected to have been agreed through an arm's length negotiation process. The arm's length nature of the Agreement has been independently verified by KPMG.[284]

The pricing structure adopted in this contract is based on a mix of fixed price quotes, unit rates and labour rates. A share of PNS' overheads is also recovered through the Network Services Agreement along with a margin of 5.26 per cent. The margin payable under this Agreement is based on the recommendations contained in a report that was prepared by Ernst & Young for CitiPower and Powercor Australia in 2006.[285] There was no incentive payment payable by CitiPower in 2008 under the Network Services Agreement.

Evidence that contract prices under the Corporate Services Agreement and Network Services Agreement are lower than the cost of in-house provision

The costs incurred by CHED Services in the provision of services to CitiPower are predominantly fixed in nature (i.e., salaries and IT infrastructure costs). The provision of services by CHED Services at a group level therefore enables CHED Services to access scale efficiencies that would not otherwise be available to CitiPower operating on a stand alone basis.[286] The nature of the services provided by PNS and the provision of these services to parties other than CitiPower and Powercor Australia (discussed in section 5.5.2.4 below) means that it too is able to access economies of scale and scope, and other efficiencies, that would not otherwise be available to CitiPower operating on a stand alone basis.

In view of the efficiencies available to both CHED Services and PNS, the service provision model adopted by CitiPower (which encompasses the Corporate Services Agreement, the Network Services Agreement and the joint provision of asset management services across CitiPower and Powercor Australia) can be expected to constitute a more efficient outcome than if the services were provided in-house on a stand-alone basis.

To test whether this is in fact the case, CitiPower retained KPMG in 2009 to quantify both:

- the efficiencies arising from the service provision model; and
- the costs that would have been incurred by CitiPower in 2008 if the services provided by CHED Services, PNS and the asset management services jointly undertaken by CitiPower and Powercor Australia had been provided by CitiPower on an in-house stand-alone basis.

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[284] KPMG, Powercor Australia Limited, Consideration of the arms length nature of the Shared Service Arrangements, December 2007 (Attachment C0092 to the Initial Regulatory Proposal), p1.

[285] Ernst and Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services, 30 November 2006 (Attachment C0048 to the Initial Regulatory Proposal).

[286] Support for this view can be found in the report prepared for ETSA by SMS Consulting that was submitted to the AER by ETSA in the context of the South Australian Final Determination (as Attachment F.11 to ETSA's Revised Regulatory Proposal 2011-15 dated 14 January 2010). In this report, SMS Consulting considered whether CHED Services could provide the FRC systems required by ETSA at a lower cost than it could achieve if it were to provide the services in-house or outsource the services to another party. SMS Consulting concluded that retaining CHED Services was the best option and in doing so referred to the benefit that ETSA would obtain because it would be able to retain *'synergies with CitiPower and Powercor with shared support resources, infrastructure and software licences support fees'*. See SMS Consulting, Review of CHED Services' forecast for FRC systems support, 25 February 2009 [commercial in confidence] (Attachment 107 to this Revised Regulatory Proposal).

KPMG's findings are set out in a report entitled, 'The efficiencies of the CitiPower Services Model'.[287]

The stand alone in-house cost provision estimate developed by KPMG does not provide a clear delineation between the services provided by CHED Services and PNS and so it has not been possible to determine whether on an individual basis, the prices payable under the Corporate Services Agreement and the Network Services Agreement are lower than the costs that would otherwise be incurred if the services provided under these Agreements were provided in-house. The results of the study do, however, allow a comparison of the costs incurred by CitiPower across its entire service provision model with the costs that would otherwise have been incurred if all of the services were provided in-house on a stand alone basis.

The principal findings emerging from this report are as follows: [288]

- CHED Services and PNS are in a better position to achieve lower costs and improved service performance than CitiPower could on a stand alone basis because they can access economies of scale in the delivery of services that that would not otherwise have been available to CitiPower; and
- If the services provided under the Corporate Services Agreement and the Network Services Agreement had been provided by CitiPower on an in-house stand alone basis then its costs would have been \$19.049 million (approximately 46 per cent) higher in 2008 than the price actually paid under the contract in that year (\$60.669 million versus \$41.620 million).[289]

In CitiPower's view, KPMG's findings provide clear evidence that the price payable under the Corporate Services Agreement and the Network Services Agreement is **lower** than the cost that would be incurred if the services were provided in-house by CitiPower. Furthermore, it demonstrates that, while CitiPower may have had an incentive to agree to non arm's length terms, it did **not** actually do so when it entered into the Corporate Services Agreement and the Network Services Agreement.

The price payable under each of these Agreements should therefore be viewed by the AER as being consistent with the opex and capex criteria contained in the Rules subject to the following two caveats:

- the price payable under the Agreements relates wholly to the provision of the standard control service; and
- there is no double counting between the contract price under these Agreements and other elements of its building block proposal.

CitiPower can confirm that the portion of the contract price under the Corporate Services Agreement and the Network Services Agreement that it has used in the derivation of

[287] KPMG, The efficiencies of the CitiPower Service Model, October 2009 (Attachment C0053 to the Initial Regulatory Proposal) and KPMG, Supplement to Report on CitiPower's service model, July 2010 (Attachment 105 to this Revised Regulatory Proposal).
[288] KPMG, The efficiencies of the CitiPower Service Model, October 2009 (Attachment C0053 to the Initial Regulatory Proposal), p3.
[289] KPMG, The efficiencies of the CitiPower Service Model, October 2009 (Attachment C0053 to the Initial Regulatory Proposal), p12.

forecast expenditure for 2011-15 in its Initial Regulatory Proposal and this Revised Regulatory Proposal relates wholly to the provision of the standard control service and does not give rise to any double counting across other elements of the building block proposal.

Assessment of non-price terms of Corporate Services Agreement and Network Services Agreement

The non-price terms and conditions specified in the Corporate Services Agreement clearly define the roles and responsibilities of both CHED Services and CitiPower and set out:

- the services to be provided (schedules 2-4), the service levels to be maintained by CHED Services (schedule 5) and the KPIs to be met over the life of the contract (schedule 6);
- the circumstances in which CitiPower can terminate the contract (clause 14.2) or seek other remedies (clause 2.5(c)-(d)) where CHED Services fails to deliver the service or meet any applicable service level or KPI;
- the reporting requirements that CHED Services must comply with (clause 6 and schedule 3); and
- the dispute resolution mechanism (clause 16) to be applied when any disputes about the price or non-price terms of the contract arise.

In a similar manner to the Corporate Services Agreement, the non-price terms and conditions specified in the Network Services Agreement clearly define the roles and responsibilities of both PNS and CitiPower and set out:

- the services to be provided (schedules 1 and 5) and the KPIs to be met over the term of the contract (schedule 3);
- the circumstances in which CitiPower can terminate the contract (clause 14.2) or seek other remedies (clause 2.5(c)-(h)) where PNS fails to deliver the service or meet the minimum KPI over each 12 month period;
- the ability of CitiPower to direct PNS to reduce the scope of, or cease to provide services (clause 3.1);
- the reporting requirements that PNS must comply with (clause 6); and
- the dispute resolution mechanism (clause 16) to be applied when any disputes about the price or non-price terms of the contract arise.

A detailed assessment of these and other provisions in the Corporate Services Agreement and Network Services Agreement is set out in Confidential Appendix 5.2 to this Revised Regulatory Proposal. In CitiPower's view, the results of this assessment demonstrate that the governance arrangements and other provisions in these Agreements give rise to an appropriate allocation of risks and responsibilities and ensure that CitiPower retains sufficient control over its assets. Based on its contracting experience, the provisions contained in these two Agreements are broadly consistent with those specified in other contracts that CitiPower has entered into with third parties. The non-price terms and conditions contained in these two Agreements may therefore be viewed as being in line with what one would expect to observe in an arm's length contract. Further support for this view can be found in KPMG's review of the arm's length nature of these two Agreements.[290]

The arm's length nature of the non-price terms and conditions specified in both the Corporate Services Agreement and the Network Services Agreement, should, in CitiPower's view, provide the AER with some additional comfort that the Agreements were **not** entered into for the purposes of transfer pricing, or to otherwise agree to non arm's length terms.

Assessment of incentives provided by the Corporate Services Agreement and the Network Services Agreement

The price payable by CitiPower for services provided under the Corporate Services Agreement is fixed for a three year period. The fixed price nature of this Agreement means that, over the term of the Agreement, CHED Services will be able to retain the benefit of any cost savings and will therefore have an incentive to pursue both productive and dynamic efficiencies.

The pricing structure adopted in the Network Services Agreement is also largely fixed, with both the unit prices and labour charges specified in the Agreement and fixed price quotes applying to projects that exceed a specified threshold. The indexation of labour charges under the Network Services Agreement also includes a productivity factor of 0.39 per cent, which provides PNS with an additional incentive to pursue productive and dynamic efficiencies. Combined these aspects of the pricing structure can therefore also be viewed as providing PNS with an incentive to pursue both productive and dynamic efficiencies.

Although not stated in either Agreement, the **actual** costs incurred by CHED Services and PNS have in the past formed the basis for determining the price to be paid in a subsequent contract term and this approach will continue going forward. Setting the new contract price by reference to the actual costs incurred by CHED Services and PNS (plus the margin recommended by Ernst & Young) means that any cost savings achieved by the two will be passed through to CitiPower at the commencement of the next contract. The two Agreements may therefore be viewed as according the contractors appropriate incentives and ensuring that the benefits of any cost savings are passed through to CitiPower, and in turn to users.

5.5.2.3 Efficiencies derived by PNS from provision of services to other parties

In section 5.5.1 above, it was noted that, if (contrary to CitiPower's contentions) the AER maintains its view that the Rules permit it to consider the costs that would be incurred by the group rather than the individual DNSP in assessing CitiPower's expenditure forecast to be incurred under the Corporate Services Agreement and the Network Services Agreement, CitiPower would nonetheless maintain that the AER cannot take into account efficiencies accruing to a contractor from the provision of services to third parties.

It would be inconsistent with the requirement, established by the opex and capex criteria, that allowed opex and capex be that reasonably required for the provision of standard

[290] KPMG, Powercor Australia Limited, Consideration of the arms length nature of the Shared Service Arrangements, December 2007 (Attachment C0092 to the Initial Regulatory Proposal), p1.

control services by the DNSP to take into account efficiencies accruing to a contractor from the provision of unregulated services. It would be unreasonable for the AER to exclude the costs associated with the provision of unregulated services from allowed opex and capex, as required by the Rules, but to take into account the benefit of any scale, scope and other efficiencies accruing to the contractor by reason of its supply of those services. It follows that, **at a minimum**, the AER's benchmark costs against which it assesses CitiPower's expenditure forecasts should not take into account efficiencies accruing to CHED Services and PNS from the supply of services to third parties.

At this point in time, PNS is the only contractor providing services to parties outside the group. Any analysis by the AER of the costs that would be incurred by the group must therefore exclude the effect of any cost savings available to PNS from the provision of these services. To provide the AER with some insight into how significant this issue is, CitiPower has reviewed PNS' 2009 Regulatory Accounts and CitiPower and Powercor Australia's 2009 Regulatory Accounts[291] to determine what proportion of its revenue was derived from parties other than CitiPower and Powercor Australia.

According to the information contained in these Regulatory Accounts, [redacted] per cent of the revenue earned in 2009 was generated from the provision of services to parties other than CitiPower and Powercor Australia.[292] The proportion of revenue accounted for by this group is not insignificant and suggests that if the AER is to maintain its position in the Final Determination, then it will need to make a material adjustment to PNS' actual costs to remove the effect of the efficiencies derived by PNS from the provision of these services.

The review of these 2009 Regulatory Accounts also revealed that the margins earned by PNS from the provision of services to CitiPower and Powercor Australia in 2009 were [redacted] those earned from the provision of services to other parties (see Table 5.2 below). The results of this study provide further confirmation that the price paid by CitiPower under the Network Services Agreement was not artificially inflated.

[291] Powercor Network Services Pty Ltd ABN 94 123 230 240, Financial Statements for the year ended 31 December 2009 (Previously provided to AER under cover of email from B Cleeve, Manager Price Review, CitiPower and Powercor Australia, to S Sandles, AER, dated 29 March 2010) (Attachment 108 to this Revised Regulatory Proposal); Powercor Australia, Regulatory Accounts, 31 December 2009 (Previously provided to the AER in soft copy under cover of an email from R Gross, General Manager Regulation, CitiPower and Powercor to C Pattas, General Manager Network Regulation South Branch, AER dated 30 April 2010 and in hard copy under cover of a letter of the same date from R Gross to C Pattas) (Attachment 121 to this Revised Regulatory Proposal); CitiPower, Regulatory Accounts for the Year Ended 31 December 2009 (Previously provided to the AER in soft copy under cover of an email from R Gross, General Manager Regulation, CitiPower and Powercor to C Pattas, General Manager Network Regulation South Branch, AER dated 30 April 2010 and in hard copy under cover of a letter of the same date from R Gross to C Pattas) (Attachment 122 to this Revised Regulatory Proposal).

[292] The derivation of this figure by reference to the PNS, CitiPower and Powercor Australia 2009 Regulatory Accounts is set out in Table 5.2 in this Revised Regulatory Proposal and the footnotes to that Table 5.2.

	Powercor Australia	CitiPower	Other	Total
Costs	[redacted]	[redacted]	[redacted]	[redacted]
Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Margin	[redacted]	[redacted]	[redacted]	[redacted]
% of Total revenue generated by PNS	[redacted]	[redacted]	[redacted]	

Table 5.2 PNS 2009 Costs, Revenue & Margins

In addition, PNS continues to expand this aspect of its business activities. For example, PNS:

- is currently tendering for a contract to provide distribution line construction and maintenance services to Energex in Queensland in one or more of its 6 regions, with a value of $8million per annum (assuming 2 regions are awarded);

[293] Letter from M Sturgess, General Manager, PNS to R Gross, General Manager Regulation, CitiPower and Powercor, 'Request for Information on Allocation of PNS 2009 Expenditure', 26 March 2010 (Previously provided to AER under cover of email from B Cleeve, Manager Price Review, CitiPower and Powercor Australia, to S Sandles, AER, dated 29 March 2010) (Attachment 120 to this Revised Regulatory Proposal), p2, table allocating PNS expenditure. The costs for Powercor Australia appearing in Table 5.2 in this Revised Regulatory Proposal are derived by summing the 'Total capital expenditure' and 'Total operating expenditure' figures for Powercor Australia in the table on p2 of this letter.

[294] Letter from M Sturgess, General Manager, PNS to R Gross, General Manager Regulation, CitiPower and Powercor, 'Request for Information on Allocation of PNS 2009 Expenditure', 26 March 2010 (Previously provided to AER under cover of email from B Cleeve, Manager Price Review, CitiPower and Powercor Australia, to S Sandles, AER, dated 29 March 2010) (Attachment 120 to this Revised Regulatory Proposal), p2, table allocating PNS expenditure. The costs for CitiPower appearing in Table 5.2 in this Revised Regulatory Proposal are derived by summing the 'Total capital expenditure' and 'Total operating expenditure' figures for CitiPower in the table on p2 of this letter.

[295] This figure is derived by deducting the PNS costs attributable to each of CitiPower and Powercor Australia (appearing in Table 5.2) from PNS' total costs (appearing in Table 5.2).

[296] Letter from M Sturgess, General Manager, PNS to R Gross, General Manager Regulation, CitiPower and Powercor, 'Request for Information on Allocation of PNS 2009 Expenditure', 26 March 2010 (Previously provided to AER under cover of email from B Cleeve, Manager Price Review, CitiPower and Powercor Australia, to S Sandles, AER, dated 29 March 2010) (Attachment 120 to this Revised Regulatory Proposal), p2, table allocating PNS expenditure. The total PNS costs for appearing in Table 5.2 in this Revised Regulatory Proposal are derived by summing the 'Total capital expenditure' and 'Total operating expenditure' figures in the 'Total' column in the table on p2 of this letter.

[297] Powercor Australia, Regulatory Accounts, 31 December 2009 (Previously provided to the AER in soft copy under cover of an email from R Gross, General Manager Regulation, CitiPower and Powercor to C Pattas, General Manager Network Regulation South Branch, AER dated 30 April 2010 and in hard copy under cover of a letter of the same date from R Gross to C Pattas) (Attachment 121 to this Revised Regulatory Proposal), p43, under the heading 'Services Fee - Powercor Network Services'.

[298] CitiPower, Regulatory Accounts for the Year Ended 31 December 2009 (Previously provided to the AER in soft copy under cover of an email from R Gross, General Manager Regulation, CitiPower and Powercor to C Pattas, General Manager Network Regulation South Branch, AER dated 30 April 2010 and in hard copy under cover of a letter of the same date from R Gross to C Pattas) (Attachment 122 to this Revised Regulatory Proposal), p40, under the heading 'Services Fee - Powercor Network Services'.

[299] This figure is derived by deducting the PNS revenues attributable to each of CitiPower and Powercor Australia (appearing in Table 5.2) from PNS' total revenues (appearing in Table 5.2).

[300] Powercor Network Services Pty Ltd ABN 94 123 230 240, Financial Statements for the year ended 31 December 2009 (Previously provided to AER under cover of email from B Cleeve, Manager Price Review, CitiPower and Powercor Australia, to S Sandles, AER, dated 29 March 2010) (Attachment 108 to this Revised Regulatory Proposal), p14, item 4. PNS' total revenue appearing in Table 5.2 of this Revised Regulatory Proposal is derived by summing the 'Construction and maintenance revenue - related parties' for 2009 and the 'Construction and maintenance revenue' for 2009 figures that appear in this item 4.

- recently secured a contract valued at $6.2million to develop all connection assets for the Gunning Wind Farm Balance of Plant Project (NSW) near the ACT; and
- recently commenced a project valued at $3million to design and construct the Country Energy Buronga Zone Substation in NSW.

The benefits to CitiPower from PNS' provision of services to third parties include:

- the development of a wider pool of specialised labour resources, e.g. training and development of apprentices, trainees, engineers, on external business activities at no cost to CitiPower;
- increased buying power in the logistics/supply chain, so reducing costs to CitiPower for equipment, materials and contracts sourced for them;
- reduced overhead costs for CitiPower as these PNS overhead costs are spread over a broader customer base;
- the benefits of innovations, e.g. in technologies, construction techniques and work practices, developed and funded through projects undertaken by PNS for third parties; and
- increased utilisation of existing labour pool and high cost equipment, which in turn reduces the costs faced by CitiPower.

5.5.2.4 Margins under Corporate Services Agreement and Network Services Agreement reflect arm's length margins

CitiPower disagrees with the AER's dismissal as irrelevant of the reports prepared by Ernst & Young on arm's length transfer prices for services of the kind provided under the Corporate Services Agreement and the Network Services Agreement. To the contrary, CitiPower maintains that those reports are relevant and establish that the margins payable by it under those Agreements reflect the margins that would be expected to be agreed to by parties operating on an arm's length basis.

It would appear that the AER has dismissed the relevance of the Ernst & Young report on the basis that differences in the assumptions underpinning the tax and economic regulatory regimes meant that it could not be *'assumed that practices which are appropriate in a tax context are always appropriate in an economic regulatory context'*.[301] CitiPower disagrees with the position taken by the AER on this issue and notes that, in a similar manner to the economic regulatory regime, the ATO's methods are designed to prevent any consideration passing between two related parties that would **not** be agreed by parties operating on an arm's length basis.[302]

[301] AER, Draft Determination, pp187-8.
[302] Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment C0049 to the Initial Regulatory Proposal), p5, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services, 30 November 2006 (Attachment C0048 to the Initial Regulatory Proposal) p4, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Customer Services (Excluding Metering), 20 November 2006 (Attachment C0050 to the Initial Regulatory Proposal) p4, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 20 November 2006 (Attachment C0051 to the Initial Regulatory Proposal) p4, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 20 May 2009 (Attachment C0052 to the Initial Regulatory Proposal) p4.

The ruling developed by the ATO on this issue provides guidance on when the costs associated with providing services to related parties should be recovered and when the costs should include a mark-up on those costs (i.e., a margin above the directly and indirectly incurred costs). In accordance with the ruling, where the provision of services to an associated entity confers a benefit on that entity then the arm's length charge should reflect the economic and commercial value of that benefit, including a margin.[303] The application of the ATO's ruling requires consideration to be given to: [304]

- the nature and the quantum of the services provided and in particular whether the services can be characterised as:
  - non-chargeable activities, i.e., if the entities were unrelated they would not be prepared to pay the other party for the activities;
  - specific benefit activities, i.e., if the entities were not related they would pay the other party for the activities; or
  - centralised services, i.e., the services benefit the related group as a whole or a particular group of related subsidiaries and must be apportioned and so a charge for the services would normally be made if the entities were dealing with each other on an arm's length basis; and
- the method that will be used to determine the arm's length charge. The methods accepted by the ATO for determining the arm's length charge include:
  - the CUP method – this method may be used where the service provided by the related entity is also provided to an unrelated entity. In such circumstances the price paid by the third party may be used to derive the charge payable by the related party; and
  - the CP method – this method calculates an arm's length mark-up by analysing the profit earned on direct and indirect costs that companies providing comparable services to third parties earn. This is the method that Ernst & Young applied to calculate the cost plus margins (measured as the ratio of EBIT to opex) for all of the services that CitiPower and Powercor Australia are provided under their respective outsourcing agreements.

CitiPower cannot understand why the AER maintains that an analysis of the profit on direct and indirect costs earned by companies providing comparable services to third parties, of

[303] Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment C0049 to the Initial Regulatory Proposal), p6, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services, 30 November 2006 (Attachment C0048 to the Initial Regulatory Proposal), p6, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Customer Services (Excluding Metering), 20 November 2006 (Attachment C0050 to the Initial Regulatory Proposal), p6, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 20 November 2006 (Attachment C0051 to the Initial Regulatory Proposal), p6, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 20 May 2009 (Attachment C0052 to the Initial Regulatory Proposal), p6.

[304] Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment C0049 to the Initial Regulatory Proposal), pp.5-8, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services, 30 November 2006 (Attachment C0048 to the Initial Regulatory Proposal), pp 5-7, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Customer Services (Excluding Metering), 20 November 2006 (Attachment C0050 to the Initial Regulatory Proposal), pp 5-7, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 20 November 2006 (Attachment C0051 to the Initial Regulatory Proposal), pp 5-7, Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 20 May 2009 (Attachment C0052 to the Initial Regulatory Proposal), pp 5-7.

the kind used by Ernst &Young in calculating the cost plus margins adopted under the Corporate Services Agreement and the Network Services Agreement, is not relevant to the objectives of the economic regulatory regime under Chapter 6 of the Rules. In CitiPower's view such an analysis is just as relevant in an economic regulatory context as it is in a taxation context, particularly against the background of CitiPower's comments on the application of theory on pricing outcomes in workably competitive markets in section 5.5.1.2 above.

The application of this approach by Ernst & Young and its findings should **not** therefore be dismissed out of hand as the AER has sought to do. Rather, the AER should accept that the recommendations contained in the various Ernst & Young reports reflect the margins that would be expected to be agreed to by parties operating on an arm's length basis and, accordingly, that the margins payable by CitiPower under the Corporate Services Agreement and the Network Services Agreement reflect the margins that would be expected to be agreed to by parties operating on an arm's length basis.

5.5.3 Discretionary Risk Management Scheme with CHED Services

For the purposes of this Revised Regulatory Proposal only, CitiPower does not contest the AER's assessment of the administration fee payable to CHED Services under the DRMS. This is because, due to an oversight, CitiPower's forecast of opex for 2011-15 in its Initial Regulatory Proposal did not include any amount in respect of the administration fee payable to CHED Services under the DRMS forecast to be incurred by CitiPower in 2011-15.

As set out in CitiPower's Initial Regulatory Proposal, CitiPower commissioned Aon to calculate the self-insurance premiums that CitiPower could expect to pay into the DRMS in each year in the 2011-15 regulatory control period.[305] The self-insurance premiums for 2011-15 calculated by Aon in its report 'CitiPower Self Insurance Risk Quantification'[306] are set out in Table 6-17 in the Initial Regulatory Proposal.[307] As disclosed by section 2.2 of the Aon report, which discusses Aon's methodology and approach to determining CitiPower's self-insurance premiums in 2011-15, Aon did not include any amount in respect of the administration fee payable to CHED Services under the DRMS in 2011-15. As the self-insurance premiums calculated by Aon constituted CitiPower's forecast opex on self-insurance for 2011-15 set out in the Initial Regulatory Proposal, it follows that CitiPower's forecast opex on self-insurance for 2011-15 in that Proposal did not include any amount in respect of the administration fee payable to CHED Services under the DRMS.[308]

[305] Initial Regulatory Proposal, pp180-1.
[306] Attachment C0066 to the Initial Regulatory Proposal.
[307] Initial Regulatory Proposal, p181.
[308] CitiPower's actual opex in the 2009 base year included the payment of an administration fee to CHED Services under the DRMS. However, the self-insurance step change was calculated by deducting CitiPower's actual opex on self-insurance in 2009 from the self-insurance premiums for 2011-15 calculated by Aon. As a result, the amount of CitiPower's forecast opex on self-insurance in the Initial Regulatory Proposal (being the sum of base year opex on self-insurance and the self-insurance step change) was set equal to the premium payable to the DRMS estimated by Aon for 2011-15. Accordingly, while CitiPower's actual opex in the 2009 base year included the payment of an administration fee to CHED Services under the DRMS, its total forecast opex on self-insurance in 2011-15 set out in the Initial Regulatory Proposal did not.

5.5.4 Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom

CitiPower disagrees with the AER's assessment of the margins payable to Silk Telecom under the Electrical Network Communications Agreement and the Corporate Communications Agreement.

CitiPower is of the opinion that the price payable under both the Electrical Network Communications Agreement and the Corporate Communications Agreement with Silk Telecom, including the implied margins, should be accepted by the AER as being consistent with the opex and capex criteria contained in the Rules and used in the derivation of forecast opex and capex for the 2011-15 regulatory control period.

CitiPower maintains that the AER must accept its forecast opex under the Electrical Network Communications Agreement and the Corporate Communications Agreement with Silk Telecom, including the implied margins, without adjustment because:

- as discussed in section 5.5.1.1 above and Appendix 5.1 to this Revised Regulatory Proposal, the opex criteria, properly construed, do not permit the AER to reduce a DNSP's total opex forecasts, for example to exclude margins under outsourcing arrangements, below the efficient costs of achieving the opex objectives;
- in deciding whether it is satisfied that CitiPower's total opex forecast reasonably reflects the opex criteria, clause 6.5.6(e)(4) of the Rules provides that the AER must have regard to benchmark opex that would be incurred by an efficient DNSP over the regulatory control period; and
- benchmarking analysis establishes that CitiPower's forecast opex for 2011-15 inclusive of any expenditure under the Electrical Network Communications Agreement and the Corporate Communications Agreement with Silk Telecom, including the implied margins, is efficiently incurred.

Section 5.5.2.1 above discusses the relevant benchmarking analysis.

In addition, CitiPower observes that:

- The AER recognised in its Draft Determination that margins above direct costs are warranted where they are necessary to enable a contractor to recover common costs and concluded that:[309]
    - the margins payable to Silk Telecom may be warranted, at least in part, to enable it to recover a reasonable allocation of its common costs; and
    - to the extent that CitiPower substantiated the appropriate allocation of Silk Telecom's common costs, it would allow a margin in the Final Determination that reflects this amount.
- The AER observed in its Draft Determination that *'the AER is not aware of any assets owned and utilised by Silk Telecom in providing services to CitiPower and Powercor which are not already contained within the DNSPs' regulatory asset bases'* but recognised that *'[t]he existence of such assets would justify a margin being paid to Silk Telecom'*.[310]

[309] AER, Draft Determination Appendices, Appendix H, p33.
[310] AER, Draft Determination Appendices, Appendix H, p33.

- As discussed in section 5.5.1 above, the NEL and the Rules necessitate an inquiry by the AER as to whether the contract price under outsourcing arrangements such as the Electrical Network Communications Agreement and the Corporate Communications Agreement with Silk Telecom exceeds the costs that would have been incurred if the services were provided in-house on a stand alone basis.
- As also discussed in section 5.5.1 above and expanded upon in section 5.5.2.3 above, even if the AER were to adopt a more stringent counterfactual than the stand-alone, in-house cost of service provision (which CitiPower does **not** concede is permissible under the Rules) then the AER should **not** take into account the efficiencies derived by the contractor, here Silk Telecom, from the provision of unregulated services or, at a minimum, services to third parties when assessing a DNSP's forecast expenditure under an outsourcing arrangement that fails the 'presumption threshold'.

In the time available, CitiPower has not been able to obtain from Silk Telecom the information required by CitiPower to determine the extent to which the margins payable by Silk Telecom may be warranted by reason of:

- the recovery by Silk Telecom of a reasonable allocation of its common costs;
- the existence of assets owned and utilised by Silk Telecom in providing services to CitiPower and Powercor Australia under the Electrical Network Communications Agreement and/or the Corporate Communications Agreement which are not already contained within their RABs;
- the contract price under the Electrical Network Communications Agreement and the Corporate Communications Agreement with Silk Telecom being lower than the costs that would be incurred if the services were provided in-house on a stand alone basis; and/or
- any scale, scope or other efficiencies accruing by reason of Silk Telecom's provision of services to parties outside the group to which CitiPower belongs.

CitiPower will continue to make efforts to obtain this information and will bring any such information obtained, together with the implications thereof, to the AER's attention at the earliest practicable opportunity. In the interim, however, CitiPower observes that:

- when Silk Telecom was part of the group to which CitiPower belongs, it had over $15 million in property plant and equipment that were directly utilised in the provision of services to CitiPower and Powercor Australia and which are not contained within their RABs; and
- Silk Telecom has significant corporate costs embedded in its structure.

Accordingly, CitiPower has not excluded these margins paid to Silk Telecom from its forecast expenditure for the 2011-15 regulatory control period in this Revised Regulatory Proposal.

5.6 CitiPower's Revised Regulatory Proposal

CitiPower's Revised Regulatory Proposal in respect of its treatment of forecast expenditure under its outsourcing arrangements with CHED Services, PNS and Silk Telecom is unchanged from that set out in its Initial Regulatory Proposal.

In summary, CitiPower maintains in this Revised Regulatory Proposal that:

- the prices payable under its Corporate Services Agreement with CHED Services, its Network Services Agreement with PNS and its Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, inclusive of margins, satisfy the opex and capex criteria;
- the margins payable under these outsourcing agreements should be included in its opex and capex forecasts for the 2011-15 regulatory control period; and
- the margins payable under these outsourcing agreements should be included in the calculation of the EBSS carry over amounts for 2011-15.

For completeness, CitiPower also observes that, for the purposes of this Revised Regulatory Proposal and for the reasons cited by the AER in its Draft Determination, CitiPower accepts the AER's conclusions in the Draft Determination that:

- the margins included in actual opex incurred for 2006-09 should be excluded in calculating the efficiency carry over mechanism amounts to be carried forward for 2011-15; and
- the margins incurred in its actual capex for 2006-09 should be included in the historical actual capex for 2006-09 that is rolled into the RAB in determining the opening RAB value for the 2011-15 regulatory control period.

6. OPERATING EXPENDITURE

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to:

- Chapter 7 of the Draft Determination in respect of opex; and
- Appendix L of the Draft Determination in respect of step changes.

CitiPower also sets out its revised opex forecast for the 2010-15 regulatory control period. CitiPower has prepared this revised forecast to be consistent with the AER's Draft Decision for other Victorian DNSPs, with the exception of specific deviations which are discussed in this Chapter which CitiPower considers are required to meet the opex objectives described in the Rules.

6.1 Summary of key points

6.1.1 Adjustments to base year opex

The AER's adjustments to CitiPower's base year opex in respect of superannuation payments and capitalisation, and to account for movement in the provisions relating to employee entitlements, were incorrect. Accordingly, CitiPower has proposed in this Revised Regulatory Proposal correct adjustments to account for movement in provisions relating to employee entitlements and in respect of capitalisation. CitiPower has retained within its base year opex all superannuation costs, however, it has applied a step change for the years 2011-15 based on an actuarial assessment of its defined benefit scheme and the increase in contributions through the accumulation fund to offset retiring employees.

CitiPower does not accept the AER's decision not to apply a customer growth factor to its allowance in respect of GSL payments and accordingly has included in this Revised Regulatory Proposal an allowance based on its average GSL payments over 2005-09 escalated with the customer growth factor set out in Chapter 7 of this Revised Regulatory Proposal.

6.1.2 Debt raising costs

CitiPower does not accept the AER's position in respect of debt raising costs. In particular, it does not agree that early refinancing costs are included in the calculation of direct debt raising costs.

6.1.3 Step changes

CitiPower does not accept the AER's decision in respect of its proposed step change for compliance with the 2010 Line Clearance Regulations. CitiPower submits that the 2010 Line Clearance Regulations will significantly increase its costs of implementing and maintaining line clearances and sets out its step change costs resulting from the changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations.

CitiPower does not accept the AER's decision to reject its proposed step change in respect of demand management at the WMTS. It is irresponsible for the AER to not provide any opex for the WMTS in circumstances where both the AER and its consultant, Nuttall Consulting, acknowledge that there is an emerging network constraint and that a response will be required to avoid the loss of supply and minimise the load at risk. While the 2009 TCPR identified four options for managing contingent risks at WMTS, the demand management option selected by CitiPower is the only prudent and efficient option.

In respect of its insurance step change, CitiPower proposes to provide the AER with invoices for its actual premiums once they become available in September 2010. CitiPower will accept a step change that reflects the difference between its 2009 and 2010 external insurance.

The AER failed to comment on CitiPower's proposed step change for communications in extreme supply events. The amendments to the Distribution Code which take effect from 1 April 2010 in respect of communications in extreme supply events will result in increased costs for CitiPower which are not reflected in its base year opex. It is necessary for the AER to allow this step change for CitiPower because the costs associated with the step change satisfy the opex criteria, as the AER has recognised in allowing a similar step change for Jemena and UED.

In this Revised Regulatory Proposal, CitiPower proposes additional step changes in respect of:

- the Commonwealth Government's announcement in respect of the superannuation guarantee levy;
- compliance with the AER's outcomes monitoring framework that is foreshadowed in Chapter 21 of its Draft Determination;
- compliance with the AER's proposed tariff assignment requirements in Appendix G of its Draft Determination; and
- Transmission-related Costs (should the AER reject its proposal to include new terms in the WAPC and side constraint formula to address Transmission-related Costs).

6.2 Rule requirements

Clause 6.5.6(c) of the Rules provides that the AER must accept the forecast of required opex that is included in a building block proposal if the AER is satisfied that the total forecast opex for the regulatory control period reasonably reflects the 'opex criteria', namely:

- the efficient costs of achieving the opex objectives (set out in clause 6.5.6(a));
- the costs that a prudent operator in the circumstances of the relevant distribution business would require to achieve the opex objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

CitiPower set out its understanding of the interpretation of this statutory test in a letter to Mr Chris Pattas of the AER dated 4 May 2010. By way of summary, CitiPower considers that there may be a range of forecasts that reasonably reflect the opex criteria.[311] CitiPower appreciates that the AER may need to assess the methodology, approaches and input values used to develop the total forecast. However, the ultimate inquiry for the AER is whether the expenditure forecast meets the statutory test. After assessing the methodologies, approaches and input values underpinning the total forecast, the AER must 'take a step back' and consider whether the forecast falls within the range that reasonably reflects the opex criteria.

The AER must balance any competing effects on the total forecast of CitiPower's choices of methodology, approach or input values to determine whether, overall, those choices mean

[311] The notion that there can be no one correct or 'best' figure was recognised by the AEMC in its Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), p52. While the statement was made in the context of the regulation of transmission businesses, it is equally applicable to the regulation of DNSPs.

the AER is not satisfied that the total forecast falls within the range that reasonably reflects the opex criteria. The AER is not permitted to reject a total forecast put forward by CitiPower because one or more of the methodologies, approaches or inputs used to develop the forecast does/do not fall within the range that reasonably reflects the opex criteria without first satisfying itself that the compound effect of the choices is such that the total forecast does not reasonably reflect the criteria.

Where a forecast put forward by CitiPower does not fall within the range of forecasts that reasonably reflect the opex criteria, clause 6.12.3(f) of the Rules provides that the AER is only permitted to amend CitiPower's forecast to the extent necessary to enable it to be approved in accordance with the Rules, that is, for the AER to be satisfied that the amended forecast reasonably reflects the opex criteria. The AER is not permitted, for example, to reduce or increase a single component of the forecast without determining whether (in light of the other components of the forecast) the change is required to ensure that the total forecast falls within the range that reasonably reflects the opex criteria and is not permitted to reduce or increase the forecast to the level it or its consultants consider most appropriate.

This approach to the Rules is consistent with the philosophy underlying economic regulation under Chapter 6 that an economic regulator should not second guess the operational decisions of the regulated business. Provided, overall, the forecasts of opex reasonably reflect the opex criteria, the expenditure should be allowed by the AER.

In addition, the complexity of forecasting opex for a five year period means that the risk of regulatory error if a 'whole of expenditure' approach is not adopted by the AER may undermine the NEO, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety and security of supply of electricity and the reliability, safety and security of the national electricity system.[312]

6.2.1 Step changes

Since clause 6.5.6(c) of the Rules requires the opex forecast to reflect the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives, the forecast must take into account all relevant changes. A positive step change may be permitted where in the next regulatory control period an efficient and prudent operator would be required to undertake new or increased activities and incur new or increased costs, which are not reflected in its 2009 efficient costs. In addition a negative step change may occur where in the next regulatory control period a prudent DNSPs' costs decrease from its 2009 efficient costs as a result of a decreased activity.

6.3 CitiPower's Initial Regulatory Proposal

In Chapter 6 of its Initial Regulatory Proposal, CitiPower:

- proposed total forecast opex for the 2011-15 regulatory control period of $243,957,000 ($2010);

[312] The highly complex nature of forecasting opex over a five year period was recognised by the AEMC in its Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), p52. While the statement was made in the context of the regulation of transmission businesses, it is equally applicable to the regulation distribution businesses.

- identified the fourth year of the 2006-10 regulatory control period being 2009 as an efficient base year;
- described the nature, aims and objectives of its forecast opex for the next regulatory control period; and
- provided information on its proposed step changes relevant to the development of its opex forecasts.

6.4 AER's Draft Determination

The AER adopted a revealed cost approach and adopted 2009 as the base year from which to assess the DNSPs' forecast opex.[313] Since CitiPower's audited actual expenditure was not available until late in the process, the AER used the unaudited base year costs as a placeholder for the DNSPs' audited 2009 costs. The AER said that it would have regard to the DNSPs' audited 2009 costs in establishing base year expenditure for its Final Decision.

The AER considered it was necessary to adjust the DNSPs' reported base year expenditure for the following in order to ensure that the costs reflected efficient costs in accordance with clause 6.5.6(c) of the Rules[314]:

- related party margins;
- movements in provisions;
- distribution licence fees;
- a reallocation of costs to AMI services;
- GSL payments;
- avoided DuOS;
- an over allocation of the related party's corporate costs to the DNSP;
- corporate cost categories that may double count costs recovered elsewhere in the regulatory regime (for example, debt raising costs) or other corporate cost categories that do not sufficiently contribute to the provision of distribution services or are not an efficient cost that would be incurred by a prudent operator;
- where necessary, the removal of non-recurrent costs to ensure that the base year costs are representative of efficient costs; and
- any changes in capitalisation policy between the current regulatory control period and the forthcoming regulatory control period.

The AER decided to roll forward the 2009 base year costs to 2010 by inflating the 2009 costs by the change in costs assumed by the ESCV in determining the benchmark opex allowance for 2009 and 2010 in its 2006-10 EDPR.[315]

The AER rejected CitiPower's proposals with respect to scale escalation, real cost escalation and debt raising costs on the basis that they did not meet the opex criteria.[316]

The AER rejected CitiPower's proposed step changes for:

- self insurance;

[313] AER, Draft Determination, p238.
[314] AER, Draft Determination, pp240-6.
[315] AER, Draft Determination, p246.
[316] AER, Draft Determination, pp249-61.

- insurance;
- climate change;
- compliance with the Electricity Safety Management Regulations;
- compliance with the 2010 Line Clearance Regulations; and
- the WMTS demand management program.

The AER failed to comment on CitiPower's proposed step change for communications in extreme supply events.

The AER accepted CitiPower's proposed step changes for the national framework for distribution network planning and expansion. The AER also accepted a step change for CitiPower in respect of the customer charter (although it reduced the amount of the step change proposed by CitiPower). The AER also gave CitiPower a step change in respect of regulatory submission costs.

6.5 CitiPower's response to AER's Draft Determination

CitiPower has reviewed all of the matters raised by the AER in its Draft Determination, including where the AER has made adjustments to CitiPower's Initial Regulatory Proposal.

CitiPower has amended its Initial Regulatory Proposal and prepared this Revised Regulatory Proposal to be consistent with the AER's Draft Determination in respect of the following:

- the AER's adjustment to base year costs to remove regulatory reset costs;[317]
- the AER's decision to roll forward the 2009 base year costs to 2010 by inflating the 2009 costs by the change in costs assumed by the ESCV, adjusted for the difference between forecast and actual growth, in determining the benchmark opex allowance for 2009 and 2010 in its 2006-10 EDPR;[318]
- the AER's decision in respect of CitiPower's proposed step change for self insurance;[319]
- the AER's decision in respect of CitiPower's proposed step change for climate change;[320]
- the AER's decision in respect of CitiPower's proposed step change for compliance with the Electricity Safety Management Regulations;[321]
- the AER's decision in respect of CitiPower's proposed step change for the national framework for distribution network planning and expansion;[322]
- the AER's decision in respect of CitiPower's proposed step change in respect of the customer charter;[323] and
- the AER's decision to include a step change for CitiPower in respect of regulatory submission costs.[324]

[317] AER, Draft Determination, p243.
[318] AER, Draft Determination, p246.
[319] AER, Draft Determination, Appendix M.
[320] AER, Draft Determination, Appendix L, p186.
[321] AER, Draft Determination, Appendix L, p159.
[322] AER, Draft Determination, Appendix L, p197.
[323] AER, Draft Determination, Appendix L, p203.
[324] AER, Draft Determination, Appendix L, p208.

CitiPower disputes the AER's Draft Determination in respect of opex in respect of the following issues:

- the AER's adjustment to base year operating costs for 2009 to account for movement in the provisions relating to employee entitlements;
- the AER's adjustment to base year and forecast costs to exclude related party margins;[325]
- the AER's adjustment to base year opex in respect of CitiPower's distribution licence fee;[326]
- the AER's adjustment to base year costs in respect of GSL payments;[327]
- the AER's adjustment in respect of capitalisation;[328]
- the AER's adjustment to base year costs in respect of superannuation payments;[329]
- the AER's decision to reject CitiPower's proposed step change in respect of insurance;[330]
- the AER's decision in respect of CitiPower's proposed step change in respect of compliance with the 2010 Line Clearance Regulations;[331]
- the AER's decision in respect of CitiPower's proposed step change in respect of the WMTS demand management program;[332]
- the AER's failure to comment on CitiPower's proposed step change for communications in extreme supply events;
- the AER's decision in respect of CitiPower's debt raising costs;
- the AER's decision in respect of scale escalation (CitiPower responds to this in Chapter 7 of this Revised Regulatory Proposal); and
- the AER's decision in respect of real cost escalation (CitiPower responds to this in Chapter 8 of its Revised Regulatory Proposal).

In addition, CitiPower proposes additional step changes in respect of:

- its defined benefit and accumulation superannuation schemes;
- the Commonwealth Government's announcement in respect of the superannuation guarantee levy;
- compliance with the AER's outcomes monitoring framework that is foreshadowed in Chapter 21 of its Draft Determination; and
- compliance with the AER's proposed tariff assignment requirements in Appendix G of its Draft Determination; and
- Transmission-related Costs (should the AER reject its proposal to include new terms in the WAPC and side constraint formula to address Transmission-related Costs).

[325] AER, Draft Determination, p242.
[326] AER, Draft Determination, p242.
[327] AER, Draft Determination, p242.
[328] AER, Draft Determination, p246.
[329] AER, Draft Determination, p244.
[330] AER, Draft Determination, pp191-2.
[331] AER, Draft Determination, Appendix L, p171.
[332] AER, Draft Determination, Appendix L, p212.

CitiPower notes that:

- The AER asked Victorian DNSPs to provide forecast expenditure associated with any avoided DuOS.[333] CitiPower observes that it does not have any avoided DuOS and forecasts that it will not have any in 2011-15.
- The AER stated that it would review CitiPower's audited 2009 accounts for its final decision and, where necessary, make an adjustment to remove any AMI related adjustments.[334] CitiPower observes that it does not have any AMI related adjustments in its audited 2009 accounts.

The aspects of the AER's Draft Determination which CitiPower disputes are expanded upon below.

6.5.1 Base year expenditure

CitiPower observes that the AER has had regard to the 10 March 2010 unaudited regulatory accounts for 2009 in its Draft Determination in respect of opex. CitiPower assumes that, as the AER has indicated, it will have regard to the final audited regulatory accounts for 2009 in establishing the base year level of expenditure its Final Determination.[335]

6.5.2 Movements in provisions

In determining the base year operating costs for 2009, the AER has made adjustments to account for movements in provisions. CitiPower does not disagree in principle with making such adjustments. However the AER made an incorrect adjustment for employee entitlements.

As set out in Chapter 14 of this Revised Regulatory Proposal. the provision adjustment for employee entitlements for 2006-09 is incorrect for the following reasons:

- The Draft Determination uses the unaudited 2009 Regulatory Accounts to calculate the provision movement. However the final 2009 Regulatory Accounts employee entitlement provision statement differs from the unaudited value.
- The Draft Determination allocates the entire employee entitlement provision movement between capex and opex. The employee entitlement provision for 2009 contains a present value adjustment for long service leave which is made in accordance with accounting standards. This adjustment is driven by assumptions in the present value calculation and therefore remains allocated to opex as per the income statement.
- The Draft Determination allocates the employee entitlement provision based on the labour costs in the Regulatory Accounts (which only includes labour costs for the licensee) whereas as it should be based on the labour costs of the ownership group. The following table provides the labour cost split for 2009 based on the ownership group.

[333] AER, Draft Determination, p242.
[334] AER, Draft Determination, p242.
[335] AER, Draft Determination, p238.

	2009
	Labour Costs
Operating Expenditure	[redacted]
Maintenance Expenditure	[redacted]
Capital Expenditure	[redacted]
Total	[redacted]

Table 6.1 Labour cost split for 2009

The second and third issues were highlighted in CitiPower's letter to the AER of 3 February 2010 regarding 'Regulatory Accounts, Provisions and AMI Adjustment to Regulatory Accounts'[336]. .

CitiPower engaged its external auditor, Deloitte to review all the movements in provisions proposed by CitiPower. Deloitte has confirmed the adjustments proposed by CitiPower to be correct.[337]

6.5.3 Exclusion of related party margins

CitiPower does not accept the AER's decision to exclude related party margins from base year opex in forecasting opex for 2011-15. CitiPower refers the AER to Chapter 5 of this Revised Regulatory Proposal which deals with outsourcing arrangements.

6.5.4 Distribution licence fees

6.5.4.1 AER's Draft Determination

The AER stated that it would exclude distribution licence fees from the Victorian DNSP's base year expenditure on the basis that distribution licence fees will be recovered on an annual basis through the weighted average price cap.[338]

The AER deducted approximately $0.6 million for CitiPower's distribution licence fees.

6.5.4.2 CitiPower's response to the AER's Draft Determination

The adjustment which the AER made for CitiPower's distribution licence fees is too high. CitiPower's actual distribution licence fees for 2009 were $161,950. Accordingly, the AER should adjust that amount from CitiPower's base year expenditure in respect of the distribution licence fee adjustment.

Attached to this Revised Regulatory Proposal is a copy of the invoice for CitiPower's 2009 distribution licence fees.[339]

[336] Attachment 217 to this Revised Regulatory Proposal
[337] Letter from T Imbesi, Partner, Deloitte, to J Williams, Chief Financial Officer, CHEDHA, titled 'CitiPower Regulatory Accounts: Accounting treatment of provisions', 20 July 2010 (Attachment 218 to this Revised Regulatory Proposal).
[338] AER, Draft Determination, p242.
[339] Attachment 129 to this Revised Regulatory Proposal.

6.5.5 Guaranteed service level payments

6.5.5.1 CitiPower's Initial Regulatory Proposal

CitiPower based its forecast of the number of GSL payments on the number of payments made in 2009 and it applied a customer growth factor to the forecasts.

6.5.5.2 AER's Draft Determination

The AER excluded CitiPower's 2009 GSL payments from its base year opex because it considered that those costs were not representative of the GSL allowance for the 2011-15 regulatory control period.[340] It provided CitiPower with a GSL allowance for the 2011-15 regulatory control period based on an average of its actual payments over 2005-09.

The AER rejected CitiPower's forecast of GSL payments based upon 2009 because it considered that GSL payments in that year appeared abnormally high.[341] Further, the AER did not accept the customer growth factor which CitiPower applied to its forecasts.

6.5.5.3 CitiPower's response to the AER's Draft Determination

CitiPower agrees that it is appropriate to exclude 2009 GSL payments from its base year opex and provide it with a GSL allowance for the 2011-15 regulatory control period based on an average of its actual payments over 2005-09.

However, CitiPower disagrees with the AER's Draft Determination not to apply a customer growth factor to the average GSL payment value. This is because by their very nature GSL payments would be expected to increase as customer numbers increase. Accordingly, CitiPower has applied the customer growth factor set out in Chapter 7 of this Revised Regulatory Proposal to its average GSL payment value.

CitiPower provides as an attachment to this Revised Regulatory Proposal a model which calculates an historic average level of GSL payments based on payments reported to the ESCV and AER during 2005-09.[342]

CitiPower's forecast GSL payments are set out in the following table.

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
GSL payments	16	16	16	16	16	**81**

Table 6.2 Forecast GSL payments

6.5.6 Capitalisation adjustment

6.5.6.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower determined the allocation of overheads in accordance with its overhead allocation policy based on its proposed capex and opex costs and service classification.[343] CitiPower proposed a step change decrease in standard control opex due to increased capitalisation of overheads as a consequence of an increase the proportion of capex to opex. CitiPower's other proposed step changes were presented

[340] AER, Draft Determination, p242.
[341] AER, Draft Determination, p687.
[342] Attachment 12 to this Revised Regulatory Proposal.
[343] Initial Regulatory Proposal, p148.

inclusive of overheads and therefore the capitalisation adjustment did not include overheads associated with those proposed step changes.

6.5.6.2 AER's Draft Determination

In its Draft Determination, the AER purported to accept CitiPower's adjustment for the reassignment of overhead costs due to increases in capital costs, referring to it as a '*capitalisation adjustment*'.[344] The AER reduced CitiPower's base level of opex by $2.9 million ($2010). The AER correspondingly increased CitiPower's capex associated with indirect overheads.

6.5.6.3 CitiPower's Response to AER's Draft Determination

CitiPower's accounting policy on overhead allocation

The following figure provides a simplified illustration of the flow of overheads between operating, maintenance and capital costs in accordance with CitiPower's accounting policy.

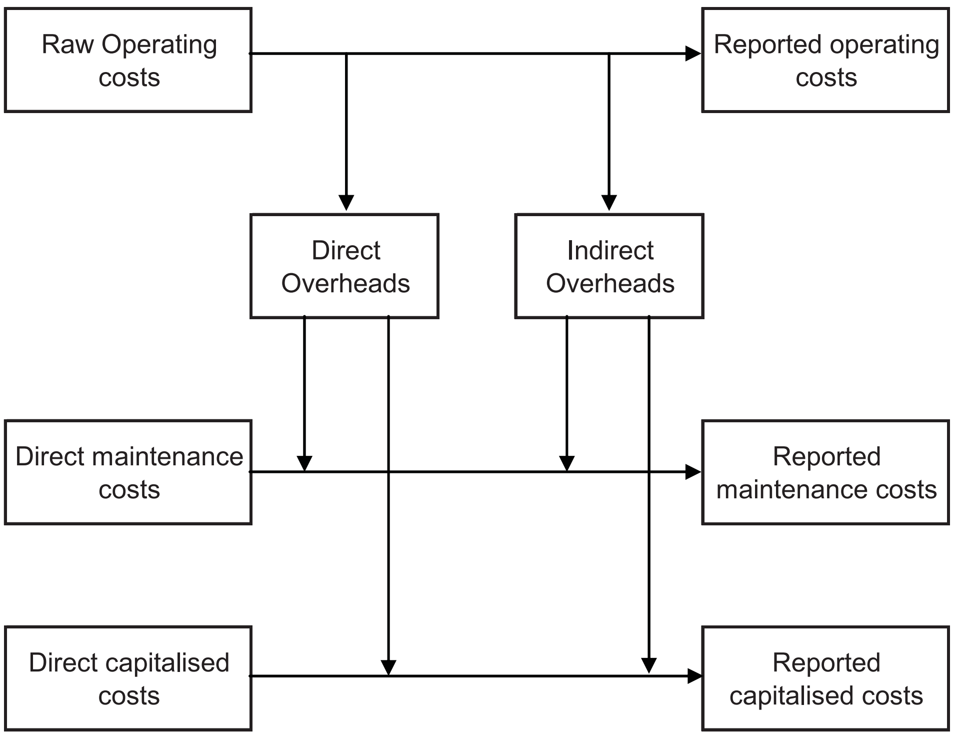

Figure 6.1 Flow of overheads between operating, maintenance and capital costs

CitiPower allocates overheads via an overhead rate which is calculated as the forecast overhead pool divided by the relevant forecast cost base. The overhead rates are calculated at least annually and are calculated inclusive of related party margins. The cost base is different for direct and indirect overheads.

Accordingly, the amount of overhead cost transferred out of opex for standard control services and the amount of overhead cost capitalised in capex for standard control services depends upon forecasts of:

344 AER, Draft Determination, p246.

- each of the overhead pool costs;
- each cost base that applies to each overhead pool;
- relative operating, maintenance and capital costs (including those step changes which attract overheads); and
- relative costs of standard control, alternative control, negotiated, metering and unregulated services.

The following scenarios show how the amount of the capitalisation adjustment depends on those factors.

1. If for the 2011-15 regulatory period the forecast costs and service classification remained unchanged from the 2009 base year, then the amount of overheads transferred out of standard control opex would remain unchanged and the amount capitalised in standard control capex would remain unchanged.
2. If for the 2011-15 regulatory period relative to the 2009 base year, overhead costs and service classification remained unchanged, but operating and maintenance costs increased at a faster rate than direct capital costs, then there would be a step change increase in standard control opex and a corresponding decrease in standard control capitalised overheads.
3. If for the 2011-15 regulatory period relative to the 2009 base year, overhead costs and service classification remained unchanged, but operating and maintenance costs increased at a slower rate than direct capital costs, then there would be a step change decrease in standard control operating costs and a corresponding increase in standard control capitalised overheads.

Errors in AER's capitalisation adjustment

In making the capitalisation adjustment, the AER made the following errors:

- the AER rejected CitiPower's forecast opex and capex, however, it applied a similar step change decrease in standard control opex due to increased capitalisation of overheads to that proposed by CitiPower;
- the AER applied the adjustment to indirect overheads only, but it should have applied the adjustment proportionally across indirect and direct overheads;
- the AER made a one-off adjustment to the 2009 base year cost which effectively assumed that the adjustment was equal in each year of the regulatory control period. However, the amount of the adjustment should vary in each year of the regulatory control period as the ratio of capex to total costs changes;
- the AER does not appear to have adjusted the amount proposed by CitiPower for related party margins. The adjustment in CitiPower's Initial Regulatory Proposal included related party margins. This is because CitiPower's accounting policies calculate and apply indirect overheads on a related party margin inclusive basis. However, the AER has excluded related party margins from forecast capex and opex in its Draft Determination. Accordingly, if the AER determines to exclude related party margins in its Final Determination, it should make an adjustment to CitiPower's proposed adjustment for margins; and
- the AER did not re-allocate the overheads associated with CitiPower's proposed step changes.

Since the AER's Draft Determination does not propose a significant increase in capital cost forecasts or a significant change in service classification relative to 2009, the Draft Determination should not have included any adjustment for the reassignment of overhead costs. That is, instead of making an adjustment of $15.2 million, it should have applied an adjustment of or near zero.

If for the purposes of its Final Determination, the AER proposes to make changes to the capex, opex and service classification which CitiPower has proposed in this Revised Regulatory Proposal, it should ask CitiPower to determine the adjustments for the reassignment of overhead costs based on the AER's decision on those matters.

If the AER fails to make adjustments which reflect CitiPower's overhead allocation policy, the AER will be in error, inconsistent with CitiPower's Cost Allocation Methodology and will distort the efficiency benefit sharing through its inconsistency in the basis on which the benchmarks have been calculated.

On the basis of the capex, opex and service classification proposed by CitiPower in this Revised Regulatory Proposal the adjustments for the reassignment of overheads are set out in the following table. This table excludes related party margins. Overheads are calculated in the Cost Forecast Model provided as an attachment to this Revised Regulatory Proposal.[345]

	$'000 ($2010)						
	2009	2010	2011	2012	2013	2014	2015
DIRECT OVERHEADS							
Overhead pool							
Standard Control capex	11,226	11,672	11,936	11,970	12,050	11,773	11,384
Standard Control O&M	2,610	2,054	2,049	2,065	2,051	2,252	2,504
Other Services	1,272	1,381	1,122	1,073	1,006	1,082	1,219
Total	**15,107**	**15,107**	**15,107**	**15,107**	**15,107**	**15,107**	**15,107**
Step change							
Standard Control capex	0	447	711	744	824	547	159
Standard Control O&M	0	(556)	(561)	(545)	(559)	(358)	(106)
Other Services	0	109	(150)	(199)	(266)	(189)	(53)
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

345 Attachment 10 to this Revised Regulatory Proposal.

INDIRECT OVERHEADS							
Overhead pool							
Standard Control capex	11,326	11,601	11,960	12,076	12,228	11,998	11,657
Standard Control O&M	4,365	3,923	3,772	3,643	3,516	3,628	3,793
Other Services	1,275	1,442	1,234	1,247	1,221	1,340	1,515
Total	**16,966**	**16,966**	**16,966**	**16,966**	**16,966**	**16,966**	**16,966**
Step change							
Standard Control capex	0	275	635	750	902	672	332
Standard Control O&M	0	(442)	(593)	(722)	(849)	(737)	(572)
Other Services	0	167	(42)	(29)	(54)	65	240
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TOTAL OVERHEADS							
Overhead pool							
Standard Control capex	22,551	23,273	23,897	24,045	24,278	23,770	23,042
Standard Control O&M	6,974	5,976	5,821	5,708	5,567	5,880	6,297
Other Services	2,547	2,823	2,355	2,319	2,228	2,422	2,734
Total	**32,073**	**32,073**	**32,073**	**32,073**	**32,073**	**32,073**	**32,073**
Step change							
Standard Control capex	0	722	1,345	1,494	1,727	1,219	490
Standard Control O&M	0	(998)	(1,154)	(1,267)	(1,407)	(1,094)	(677)
Other Services	0	276	(192)	(228)	(319)	(125)	187
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 6.3 Adjustments for overheads (excluding input escalation, scale escalation and related party margins)

6.5.7 Debt raising costs

6.5.7.1 CitiPower's Initial Regulatory Proposal

In Chapter 6 of its Initial Regulatory Proposal, CitiPower included debt raising costs as an element of its opex forecasts. CitiPower proposed the following debt raising costs:

- direct debt raising costs of 12 basis points per annum; and

- early debt refinancing costs of 16.6 basis points per annum.[346]

6.5.7.2 AER's Draft Determination

The AER did not accept CitiPower's proposed debt raising costs. In Appendix P of its Draft Determination, the AER concluded that:

- the appropriate amount of direct debt raising costs was between 9.0 and 10.8 basis points per annum, depending on the number of debt issues;[347]
- early debt refinancing costs were a legitimate expense for which DNSPs should be compensated;[348]
- the AER's estimate of the amount of early debt refinancing costs was 4-8 basis points per annum, based on the underwriting method;[349]
- however, the AER considered that the costs of early debt refinancing were already included in the direct debt raising costs and an additional allowance for early debt refinancing costs was not appropriate.[350]

6.5.7.3 CitiPower's Response to AER's Draft Determination

CitiPower does not accept the AER's position in relation to debt raising costs.

CitiPower considers that the appropriate allowance for debt raising costs is a total of 24.6 basis point per annum. This allowance is made up of direct debt raising costs of 9.1 basis points and early refinancing costs of 15.5 basis points. This allowance needs to be updated in the Final Determination to use the agreed averaging period.

CitiPower does not agree that early refinancing costs are included in the calculation of direct debt raising costs.

CitiPower's forecast debt raising costs are set out in the following table.

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Debt raising costs	1,853	2,025	2,200	2,392	2,568	**11,038**

Table 6.4 Debt raising costs

6.5.8 Step change - Superannuation payments

6.5.8.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower observed that its contributions to the defined benefit scheme have been very volatile as a result of turbulent market conditions during the last couple of years.[351] However, the effects of the deteriorating market conditions and the reduced value of investments related to the defined benefit schemes have lead to an increase

346 Initial Regulatory Proposal pp214-15.
347 AER, Draft Determination, Appendix P, p337.
348 AER, Draft Determination, Appendix P, p345.
349 AER, Draft Determination, Appendix P, p343.
350 AER, Draft Determination, Appendix P, p345.
351 Initial Regulatory Proposal, p227.

in the required contribution rates, particularly in 2009. CitiPower stated that the volatility in defined superannuation contributions has resulted in a variation between CitiPower's actual expenditure and the ESCV's approved allowance.

6.5.8.2 AER's Draft Determination

The AER considered that fluctuations in required superannuation contributions are likely to be broadly symmetrical because financial market conditions are likely to fluctuate such that any actuarial adjustments are likely to balance out over time.[352] Nonetheless, the AER considered that the impact of the recent GFC was such that any actuarial adjustments related to defined benefit scheme contributions reflected in the reported base year costs were unlikely to be consistent with the level of costs expected to occur in the forthcoming regulatory control period.

The AER said that to ensure the reported base year costs were reflective of an efficient level of expenditure, the AER required Victorian DNSPs to identify any actuarial adjustment to defined benefit scheme contributions in 2009 where those adjustments were included in the Victorian DNSPs' Regulatory Accounts.

The AER estimated CitiPower's actuarial adjustment to defined benefit scheme contributions to be $1.7 million ($2010) and removed this amount from CitiPower's base year opex. The AER said it would require CitiPower to identify the actuarial adjustment for its Final Determination and whether the adjustment was included in the Regulatory Accounts.

In addition, in its Draft Determination, the AER failed to have regard to the changes to the superannuation guarantee levy announced by the Commonwealth Government following the Henry Review. In Chapter 12 of its Draft Determination relating to corporate income tax, the AER refers to the announcements made by the Commonwealth Government on 11 May 2010 arising out of the Henry Review.[353] However, the AER focuses on the changes announced in relation to the corporate tax rate being to reduce it to 29 per cent for 2013-14 and to 28 per cent from the 2014-15 financial year and concludes that these changes should be reflected in the expected statutory corporate income tax rate under clause 6.5.3 of the Rules.

6.5.8.3 CitiPower's response to AER's Draft Determination

In response to the AER's Draft Determination, CitiPower proposes the following step changes in respect of superannuation:

- a step change in respect of contributions to its defined benefit fund and accumulation fund; and
- a step change as a result of the Commonwealth Government's announcement in respect of changes to the superannuation guarantee levy.

Step change - defined benefit fund and accumulation fund contributions

The AER's adjustment of $1.7 million to CitiPower's base year opex is incorrect. Firstly, the adjustment is based on all superannuation contributions rather than the defined benefits contribution portion. Secondly, it uses as a base the costs incurred over 2006-08 which are artificially low as a result of favourable market conditions during that time.

[352] AER, Draft Determination, p244.
[353] AER, Draft Determination, p555.

CitiPower has therefore preserved in its base opex for 2009 all superannuation costs associated with the defined benefit superannuation scheme. It has then applied a step change for the years 2011-15 based on the difference between 2009 defined benefit contributions and an actuarial assessment of its defined benefit superannuation scheme as determined by Mercer, the actuary for the fund.[354] Mercer's Report is attached to this Revised Regulatory Proposal.[355] In addition, CitiPower has provided the cost build up model for this step change as an attachment to this Revised Regulatory Proposal.[356]

The Draft Determination assumes that accumulation fund contributions will remain constant at 2009 levels. This is by virtue of the 'revealed cost' model adopted by the AER. CitiPower however expects to experience strong growth in its requirements to make contributions into the accumulation fund over the next five years that are not otherwise compensated through scale escalation.

Mercer's Report shows that it is projected that the number of employees who are active members of the defined benefit scheme will decline significantly, and at an increasing rate, as they retire from the workforce over the period 2011-15.[357] CitiPower will be required to replace these employees. All new employees must join the accumulation fund. Consequently contributions to the accumulation fund will grow strongly over the next regulatory control period through the replacement of employees (as opposed to additional employees who would be funded through scale escalation).

As set out in the following table, the superannuation step change comprises the effects of the Mercer Report projections for the defined benefit fund over the next regulatory control period plus an adjustment to the accumulation fund for those new employees replacing those who have departed the defined benefit fund.

	$'000 ($2010)					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Mercer Report forecast defined benefit fund contributions	-72	-236	-388	-531	-669	**-1,895**
Incremental increase in accumulation fund contributions to replace employees who have departed the defined benefit fund	227	421	627	851	1,111	**3,236**
Total step change	**155**	**185**	**238**	**320**	**442**	**1,341**

Table 6.5 Step change - defined benefit fund and accumulation fund contributions

354 Letter from D Scott, Mercer, to T Mutton, CitiPower and Powercor, dated 28 June 2010 regarding projected superannuation expense under AASB 119 (Attachment 123 to this Revised Regulatory Proposal); Letter from D Scott, Mercer, to T Mutton, CitiPower and Powercor, dated 28 June 2010 regarding interim AASB 119 results – six months ending 30 June 2010 (Attachment 124 to this Revised Regulatory Proposal).

355 Letter from D Scott, Mercer, to T Mutton, CitiPower and Powercor, dated 28 June 2010 regarding projected superannuation expense under AASB 119 (Attachment 123 to this Revised Regulatory Proposal); Letter from D Scott, Mercer, to T Mutton, CitiPower and Powercor, dated 28 June 2010 regarding interim AASB 119 results – six months ending 30 June 2010 (Attachment 124 to this Revised Regulatory Proposal).

356 Attachment 13 to this Revised Regulatory Proposal.

357 Letter from D Scott, Mercer, to T Mutton, CitiPower and Powercor, dated 28 June 2010 regarding projected superannuation expense under AASB 119 (Attachment 123 to this Revised Regulatory Proposal), p2.

Step change – Superannuation guarantee levy

In its Draft Determination, the AER has ignored changes following the Henry Review which will result in increased costs for DNSPs. Following the Henry Review, in addition to changes to the corporate tax rate the Commonwealth Government announced an intention to increase the superannuation guarantee levy to 12 per cent.[358] Under the Commonwealth Government's plan, the superannuation guarantee levy will be increased by 0.25 percentage points on 1 July 2013 and again on 1 July 2014. Further increments of 0.5 percentage points will apply annually up to 2019-20 when the superannuation guarantee rate will be set at 12 per cent. If this recommendation comes into effect through legislation, it will increase the superannuation liability of CitiPower.

CitiPower has calculated that the proposed changes to the superannuation guarantee levy would result in a step change over 2013-15 in accumulation payments, prior to escalation. CitiPower has provided the cost build up model for this step change as an attachment to this Revised Regulatory Proposal.[359]

CitiPower considers that should the AER reconfirm its position to make decisions based on Government policy announcements following the Henry Review before they are reflected in legislation as it has done in the Draft Determination in respect of estimated corporate income tax, it should also have regard to the changes associated with the superannuation guarantee levy and accept this step change amount.

	$'000 ($2010)			
	2013	2014	2015	Total
Superannuation guarantee levy	21	68	147	**236**

Table 6.6 Incremental impact of increase in the superannuation guarantee levy on accumulation fund contributions (assumes no growth in employee numbers)

6.5.9 Step change – insurance

6.5.9.1 CitiPower's Initial Regulatory Proposal

In Chapter 6 of its Initial Regulatory Proposal, CitiPower proposed a step change of $7 million for opex resulting from insurance premiums above those reflected in CitiPower's 2009 base year opex.[360]

CitiPower provided the AER with a report prepared by its insurance broker Aon which provided an estimate of its insurance costs to 2015. Aon's report identified that CitiPower's

[358] Australian Government, Fact Sheet Superannuation – Increasing the Superannuation Guarantee Rate to 12 per cent (Attachment 131 to this Revised Regulatory Proposal); Australian Government, webpage entitled 'Banking the benefits of the boom with fairer concessions for Super' accessed on 12 July 2010 (Attachment 132 to this Revised Regulatory Proposal).
[359] Attachment 13 to this Revised Regulatory Proposal.
[360] Initial Regulatory Proposal pp170-1.

insurance premiums were likely to increase considerably in the next regulatory control period.[361]

CitiPower observed that appropriate insurance coverage was a critical element of its approach to risk management and it was not an option for it to avoid taking out appropriate insurance coverage by not paying the increased premiums. CitiPower observed that clause 6.5.6(a)(4) requires the building block proposal to include the forecast opex for the regulatory control period which the DNSP considers is required to, among other things, maintain the reliability, safety and security of the distribution system through the supply of standard control services. 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.

6.5.9.2 AER's Draft Determination

The AER was not satisfied that CitiPower's proposed insurance step change reasonably reflected the opex criteria.

The AER observed that Aon identified asset value growth and revenue growth as 'business trend' drivers and applied one of these drivers to CitiPower's insurance premiums.[362] It considered that Aon had not explained why it chose these particular drivers or demonstrated that CitiPower's premiums had moved in line with their asset value growth or revenue growth. The AER also considered that the business trend drivers appeared to play a similar role to opex scale adjustments. Since the AER had applied scale adjustments to the total opex base in its Draft Determination, it considered that it would lead to double counting if it accepted the business trend escalators.

The AER considered that Aon had not demonstrated that CitiPower's historical insurance premiums had moved in line with movements in the general insurance market such that it might be reasonable to assume their future insurance premiums would move in line with these factors.[363]

In respect to liability (including bushfire liability) premiums, the AER considered that there was no clear link between the factors raised by Aon and the percentage increases it estimated.[364]

The AER accepted an insurance step change of $15 million for SP AusNet subject to it submitting invoices with its regulatory proposal which verified this increase in its liability insurance premiums in September 2009.

The AER accepted an insurance step change of $3.5 for UED after verifying this step change against the renewal report submitted by UED.

6.5.9.3 CitiPower's Response to AER's Draft Determination

CitiPower observes that its insurance program is undertaken jointly with Powercor Australia and ETSA. The AER decided that ETSA forecast network insurance opex reasonably reflected the opex criteria. Similar to CitiPower and Powercor Australia, ETSA commissioned Aon to provide an estimate of its insurance costs for the next regulatory

[361] Aon Risk Services Australia, CitiPower Insurance Cost Projections, October 2009 (Attachment C0067 to the Initial Regulatory Proposal).
[362] AER, Draft Determination, Appendix L, p189.
[363] AER, Draft Determination, Appendix L, p190.
[364] AER, Draft Determination, Appendix L, p191-2.

control period. PB reviewed Aon's report at the AER's request. The AER observes in its South Australian Draft Determination that:[365]

> '*PB submit that given the transparent approach adopted by AON Risk Services and the nature of the insurance classes included in ETSA Utilities' 2008-09 insurance costs and the potential impact of bushfire and environmental factors outlined, PB was satisfied that ETSA Utilities' forecast network insurance allowances are prudent and efficient.'*

In deciding to accept ETSA forecast network insurance opex, the AER stated:[366]

> *'The AER considers it appropriate that ETSA Utilities commissioned AON Risk Services to provide an estimate of its insurance liabilities for the next regulatory control period. The AER also considers the approach undertaken by AON Risk Services is transparent and reasonable and agrees with PB's assessment that ETSA Utilities' forecast network insurance allowances are prudent and efficient. The AER notes that AON Risk Services concluded that ETSA Utilities are likely to experience increased insurance costs as a result of both business growth and rate increases caused by general market trends.'*[367]

Accordingly, in its South Australian Final Determination the AER accepted the Aon report prepared at the request of ETSA Utilities as transparent and reasonable. Further, contrary to the Draft Determination for CitiPower, the AER accepted the asset value growth and revenue growth as 'business trend' drivers chosen by Aon in its report for ETSA .

Similar to CitiPower, ETSA did not apply any additional scale escalation to its forecast for insurance premiums since it considered that Aon's estimate gave consideration to scale factors.[368] However, as in the Draft Determination for Victorian DNSPs, in the South Australian Final Determination, the AER applied scale escalation to the total opex base. In its Draft Determination, the AER rejected CitiPower's insurance step change in part because the AER had applied scale adjustments to the total opex base and it considered that if it accepted the business trend escalations in the Aon report, this would lead to 'double counting'.[369] It is inconsistent for the AER to reject CitiPower's insurance step change on this basis when it accepted ETSA's insurance step change at the same time as applying scale escalation to the total opex base.

There is no basis for the AER accepting the Aon report for ETSA in the South Australian Final Determination, but rejecting the Aon report prepared for CitiPower in its Draft Determination. This is particularly so given the acceptance of the analogous Aon report prepared for ETSA was accepted by the AER's own expert, PB, as providing transparent and reliable estimates of prudent and efficient forecast network insurance allowances. There is similarly no basis for the AER rejecting CitiPower's proposed step change for insurance in circumstances where CitiPower and ETSA have a joint program with respect to insurance and the AER accepted ETSA's network insurance opex.

The AER's Draft Determination indicates that the AER requires proof of CitiPower's insurance renewal amount for 2010 in order to accept an insurance step change for CitiPower.

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[365] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p220.
[366] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p221
[367] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p221.
[368] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p220.
[369] AER, Draft Determination, Appendix L, p189.

CitiPower's process for renewing its insurance is currently taking place. CitiPower will not have its actual insurance premiums until September 2010. Accordingly, CitiPower is not currently in a position to provide the AER with invoices showing its actual insurance premiums. CitiPower proposes to provide the AER with those invoices as soon as it is able to, which will likely be on 30 September 2010. CitiPower's process for insurance renewal is thorough and, accordingly, lengthy. CitiPower provides a description of this process in the table below.

The following table details the process undertaken in respect of acquiring combined liability underwriting insurance for CitiPower, Powercor Australia and ETSA. It includes the preparation of a liability marketing submission which is written in conjunction with each of the business areas and covers the key activities of bushfire mitigation, an update on business activities over the last 12 months and business exposure and risk management activities to mitigate these risks.

Month	Activity
October	• Renew the insurance liability submission (copy provided to the insurance underwriters) to identify any improvements in the Businesses' internal processes.
December	• Advise senior management team of the combined liability insurance renewal process for the coming year and seek nominated representatives from each Business Unit. • Review prior year liability submission and determine Business Unit representatives for coming year – a spreadsheet is set up detailing sections from the prior year submission, Business Unit, General Manager, updating officer, date the section was sent, date received, date updated and any other comments. • Prior year liability submission is broken down into sections to send to the updating officer.
January	• Liability underwriting submission is sent to updating officers requesting that the section be reviewed, updated as appropriate and new information is provided accordingly. • Any changes to updating officers are noted and updated on the spreadsheet.
April	• Prepare current year liability submission. • Ensure that the Business' responses are accurate and that there is a consistency of writing format of the submission. • Link into the annual report to ensure consistency in reporting. • Receive updates from the Business and update the spreadsheet. • Review company documentation and external data to support liability submission. • Review undertaken of liability submission by Corporate Risk team.
May	• Send out annual report to insurance underwriters. • Final review undertaken of the liability submission by the Corporate Risk team. • Review and signoff by the Senior Management Team on liability submission. • Liability submission sent to printer for proofing. • Liability strategy meeting with insurance broker.
June	• Final copy of the liability underwriting submission received from the printer.

	• Distribute the liability underwriting submission to insurance underwriters around the world through the insurance broker. • Complete insurance documentation for the Bermuda market.
July	• Participate in the marketing liability roadshow in the major insurance markets around the world. • Meet with current and prospective insurance underwriters.
August	• Participate in the Australian insurance market roadshow. • Prepare risk Management and Compliance Committee papers.
September	• Review quotations and insurance options provided by the insurance broker. • Ensure that insurance underwriters meet the credit rating criteria per company credit policy. • Ensure that appropriate senior management approvals are received for the placement of the insurance. • Ensure insurance is placed and that Business risk exposure is mitigated. • Review of process undertaken and identification of improvement opportunities for the next year.
October	• Payment of invoices

Table 6.7 CitiPower's Insurance Renewal Process

CitiPower will accept a step change that reflects the difference between its 2009 and 2010 external insurance. However, since CitiPower will not have its actual insurance premiums until September 2010, for the purposes of this Revised Regulatory Proposal CitiPower has used a placeholder assumption for the insurance step change based on a 15 per cent increase in the insurance premium reported in its 2009 Regulatory Accounts.

The step change for insurance based on this placeholder assumption is set out in the table below.

	$'000 ($2010)					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Insurance step change	132	132	132	132	132	**661**

Table 6.8 Insurance step change

6.5.10 Step change – Electricity Safety (Electric Line Clearance) Regulations 2010

6.5.10.1 CitiPower's Initial Regulatory Proposal

CitiPower omitted in its Initial Regulatory Proposal to identify the step change costs of complying with the requirements of the 2005 Line Clearance Regulations and 2005 Line Clearance Code in respect of LBRA.

In addition, the 2010 Line Clearance Regulations and 2010 Line Clearance Code replaced the 2005 Line Clearance Regulations and Code on 29 June 2010. In its Initial Regulatory

Proposal of 30 November 2009 CitiPower did not propose a step change for changes in costs of complying with the 2010 Line Clearance Regulations and the 2010 Line Clearance Code as the those Regulations and Code had not yet been released for public comment. Rather, CitiPower proceeded on the assumption that the 2010 Line Clearance Regulations and Code would be the same as the 2005 Line Clearance Regulations and Code. However, subsequent to the release of the proposed 2010 Line Clearance Regulations on 25 February 2010, CitiPower provided the AER with estimates of the cost impact of the then proposed Regulations.

Since that time, the 2010 Line Clearance Regulations and 2010 Line Clearance Code have come into effect. As set out in this Revised Regulatory Proposal, there are several key changes between the 2005 Line Clearance Regulations and Code and the 2010 Line Clearance Regulations and Code which will increase CitiPower's costs of complying with the 2010 Line Clearance Regulations and Code.

6.5.10.2 AER's Draft Determination

In its Draft Determination, the AER observed that on 25 February 2010, after the DNSPs submitted their regulatory proposals, the ESV published a draft for public comment of the proposed 2010 Line Clearance Regulations together with the Line Clearance RIS. The final version of the 2010 Line Clearance Regulations varies only slightly to the draft which the ESV published for public comment on 25 February 2010.

The AER said it expected that when the 2010 Line Clearance Regulations commenced, they would likely increase the DNSPs' opex requirements.[370] Accordingly, the AER anticipated that the DNSPs would include in their revised regulatory proposals an opex step change for increased vegetation management activities under the 2010 Line Clearance Regulations.

In the meantime, for the purposes of the Draft Determination, the AER sought to estimate the step change costs of complying with the 2010 Line Clearance Regulations, including costs flowing from the cessation of the exemptions.

The AER noted that the Line Clearance RIS identified four changes in the then proposed line clearance regulations that will impact the DNSPs:

- updating of management plans;
- providing written notification to affected persons;
- clearance space surrounding aerial bundled cables; and
- overhanging branches in HBRA.

The AER observed that as part of the cost benefit analysis in the Line Clearance RIS, the ESV estimated the cost to DNSPs of complying with both the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations. The AER sought to estimate the step change cost for DNSPs of complying with the 2010 Line Clearance Regulations by reference to the cost benefit analysis in the Line Clearance RIS (by deducting the costs to DNSPs of complying with the 2005 Line Clearance Regulations estimated in the Line Clearance RIS from the estimated costs of complying with the 2010 Line Clearance Regulations).

[370] AER, Draft Determination, Appendix L, p162.

In respect of costs resulting from the cessation of the exemptions, the AER found that it was not satisfied that the DNSPs' proposed expenditure for the cessation of line clearance exemptions reasonably reflected the opex criteria.[371]

The AER calculated a step change of $1.2 million for CitiPower.[372]

6.5.10.3 CitiPower's response to AER's Draft Determination

CitiPower's detailed response to the AER's Draft Determination is contained in Appendix 6.1 to this Revised Regulatory Proposal. In that response, CitiPower:

- explains that the AER cannot rely on the cost impact analysis in the Line Clearance RIS[373] in determining the step change costs of complying with the 2010 Line Clearance Regulations. This is because the Line Clearance RIS failed both to correctly identify the key changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations, and to correctly cost compliance with the 2010 Line Clearance Regulations as compared with the 2005 Line Clearance Regulations. As the AER is aware, ESV has expressly told the AER that it cannot rely on the cost impact analysis in the Line Clearance RIS for the purpose of determining the step changes in the price review process;[374]
- describes the changed regulatory obligations resulting from the changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations;
- sets out the step change costs resulting from the changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations; and
- sets out the step change cost of achieving compliance in respect of LBRA.

As set out in Appendix 6.1, CitiPower's vegetation clearance contractor, VEMCO has considered the cost impact of each of the changes between the 2010 Line Clearance Regulations and the 2005 Line Clearance Regulations based on legal advice on those changes provided by DLA Phillips Fox dated 21 June 2010.[375] VEMCO has provided a letter dated 13 July 2010 to CitiPower in respect of the cost increases above 2009 actual costs that will apply over the years from January 2011 to December 2015.[376] Since VEMCO is engaged by CitiPower to undertake vegetation clearance in accordance with the 2010 Line Clearance Regulations, these costs reflect the increased costs CitiPower will be required to pay under the 2010 Line Clearance Regulations. CitiPower submits that the AER should accept those step change costs as reasonably reflecting the opex criteria.

CitiPower has revised its Initial Regulatory Proposal to include the following step change costs in respect of vegetation clearance.

[371] AER, Draft Determination, Appendix L, p170.
[372] AER, Draft Determination, Appendix L, p171.
[373] Attachment 241 to this Revised Regulatory Proposal.
[374] Meeting with the AER, ESV and Victorian DNSPs on 13 July 2010.
[375] Attachment 244 to this Revised Regulatory Proposal.
[376] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – lines from pole to pole	309	309	309	309	309	**1,545**
Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – service lines from pole to building	2,712	2,712	2,712	2,712	2,712	**13,558**
Vegetation Clearance (omission of clauses 10(b) and (c) and tables 10.2 and 10.3)	990	594	594	594	594	**3,366**
Vegetation Clearance (notification and consultation)	(1)	(1)	(1)	(1)	(1)	**(5)**
Vegetation Clearance (clause 2(3) native trees)	0	18	46	92	123	**280**
Vegetation Clearance (LBRA)	165	91	32	(3)	165	**450**
Total Vegetation Clearance Step Change	**4,175**	**3,723**	**3,692**	**3,703**	**3,902**	**19,194**

Table 6.9 Step changes – Electricity Safety (Electric Line Clearance) Regulations

6.5.11 Step change – Electrical Safety (Management) Regulations 2009

6.5.11.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower proposed a $1,369,000 step change in respect of changes to the Electricity Safety Act which make it compulsory for DNSPs operating in Victoria to submit and operate under an approved ESMS.[377] The changes will make the provisions of the proposed Electricity Safety Management Regulations mandatory for DNSPs, whereas the provisions of the current regulations apply only where the DNSP has voluntarily elected to develop an ESMS.

6.5.11.2 AER's Draft Determination

In its Draft Determination, the AER concluded that CitiPower had not justified that it required additional opex, above that expended in the 2009 base year to achieve compliance with their ESMS.[378]

In coming to this conclusion the AER relied on the ESV's advice to it that the Electrical Safety Management Regulations would not increase the ongoing compliance costs of the

[377] Initial Regulatory Proposal, p177.
[378] AER, Draft Determination, Appendix L, p159.

Victorian DNSPs and that any additional costs would be borne in the current regulatory control period.[379]

6.5.11.3 CitiPower's response to AER's Draft Determination

CitiPower has accepted the AER's decision to reject this step change on the basis of the ESV's advice that the Electrical Safety Management Regulations would not increase the ongoing compliance costs of the Victorian DNSPs and that any additional costs would be borne in the current regulatory control period. CitiPower assumes that the ESV will honour this position when deciding whether or not to approve ESMSs.

CitiPower has proposed a pass through for conditions or limitations imposed by ESV on provisional acceptance of an ESMS under the Electricity Safety Act (see Chapter 17 of this Revised Regulatory Proposal).

6.5.12 Step change – West Melbourne Demand Management

6.5.12.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower proposed a step change for West Melbourne Demand Management.[380] CitiPower has substantial capital works projects that will continue over the next regulatory control period to reduce the energy at risk at WMTS and Richmond Terminal Station.

While the energy at risk at West Melbourne will decline through the transfer of load to Brunswick Terminal Station as a result of the Metro 2012 project,[381] the necessary works will not be completed until late 2013. As a consequence in the interim period 2011-13, it will be necessary for CitiPower to seek alternate arrangements to ensure the security of the network in the areas supplied by WMTS.

CitiPower decided that the demand management option was the only prudent and efficient option to ensure the security of the network in the areas supplied by WMTS.

6.5.12.2 AER's Draft Determination

Both the AER and Nuttall Consulting acknowledged that the load forecasts for WMTS identified an emerging network constraint and that a response would be required by CitiPower to avoid the loss of supply and minimise the load risk.[382]

The AER noted that the 2009 TCPR identified four options for managing the contingent risks at WMTS and that Nuttall Consulting concluded that it would have been prudent if the costs and benefits of these options had been considered. The AER agreed with Nuttall Consulting and considered that CitiPower's options analysis was incomplete and failed to demonstrate the efficiency of the chosen option over the alternatives.

The AER agreed with Nuttall Consulting that the expenditure proposed by CitiPower was not supported and therefore removed this proposed step change from CitiPower's opex allowance.

[379] AER, Draft Determination, Appendix L, p158.
[380] Initial Regulatory Proposal, p177.
[381] 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 WMTS (Initial Regulatory Proposal p85).
[382] AER, Draft Determination, p212; Nuttall Consulting, Capital Expenditure – Victorian Electricity Distribution Revenue Review, 26 May 2010 p354.

6.5.12.3 CitiPower's response to AER's Draft Determination

It is irresponsible for the AER to not provide any opex for the WMTS in circumstances where both the AER and its consultant, Nuttall Consulting, acknowledge that there is an emerging network constraint and that a response will be required to avoid the loss of supply and minimise the load at risk.

As the AER and Nuttall Consulting have observed, the 2009 TCPR identified four options for managing the contingent risks at WMTS, apart from permanently transferring the load from WMTS 66kV to the proposed Brunswick termination station (which will occur at the completion of the Metro 2012 project).[383]

However, only one of those options, the demand management option, is prudent and efficient. CitiPower reviewed each of those options in deciding that the demand management option was the only prudent and efficient option. One of the four options placed CitiPower's distribution network in a first order contingency, which is not compliant with the Distribution Code or CitiPower's network planning standards. Another option rejected by CitiPower which concerned embedded generation is not considered to be a genuine or practicable alternative since CitiPower is not currently aware of any proponents of embedded generation that would be capable of alleviating the constraints identified.

The four options referred to in the 2009 TCPR are:

- **Option 1:** A contingency plan to transfer load to the adjacent terminal stations under transformer outage conditions. This option requires works to be carried out to increase the N rating to the normal four-transformer capacity level of the station by:
    - installing a, 66kV series react across the 66kV bus tie with an 'auto-switching' scheme to control the 66kV station fault level; and
    - re-arranging the 66kV sub-transmission network into two groups separated by the 66kV bus tie series reactor for station fault level control.
- **Option 2:** A contingency plan to utilise the capacity of the 'Normal Open' 220/66kV transformer to temporarily avoid automatic load shedding by Overload Shredding Scheme of Connection Asset under the 10th percentile conditions with no transformer outage. This is done by radially supplying one zone substation (about 110MVA of load) by a single transformer, while the other three transformers supply the remaining terminal station loads.
- **Option 3:** Demand reduction. An opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction depends on the customer uptake and would be taken into consideration when determining the optimum timing for the capacity augmentation.
- **Option 4:** Embedded generation in the order of about 150MVA to help defer the need for augmentation.

Of these options CitiPower has decided that option 3, the demand reduction option, is the only prudent and efficient option. This is because under this option there will be no compromise to network security under the majority of peak demand days. As noted above, under this option the amount of demand reduction depends on the customer uptake which would be taken into consideration when determining the optimum timing for the capacity

[383] 2009 TCPR, WMTS 66kV (Attachment 251 to this Revised Regulatory Proposal), pp4-5.

augmentation. The cost build up model for this option was provided to the AER by email on 8 February 2010. It is provided again as an attachment to this Revised Regulatory Proposal.[384]

CitiPower's reasons for rejecting the other options are provided below.

Option 1

The approximate cost of this option in $2010 is $10 million which comprises:

- $5.5 million for the series reactor. This is based on a recent estimate from SP AusNet for 2 x 1.3 ohm reactors at Brooklyn Terminal Station at a cost of $7.1 million. A copy of SP AusNet's letter to CitiPower of 6 May 2010 is provided as an attachment to this Revised Regulatory Proposal.[385] This does not include the cost of a 66kV circuit breaker which would be required at WMTS; and
- $4.5 million for re-arranging the 66kV sub-transmission network.

As set out in the SP AusNet letter, the lead time for fault limiting reactors is typically 18 months. Accordingly, the lead time for implementing this option is at least 18 months. In addition, the implementation of these works will only permit the WMTS to be loaded beyond the N-1 rating and load transfer away from WMTS would still be required under transformer outage condition thus placing the surrounding network in a first order contingency situation. In comparison the demand management option can be implemented at call once commercial agreements are finalised and does not jeopardise any significant part of the network.

Option 2

This option places the CitiPower network in an unsecure position, which is not compliant with the requirement in respect of good asset management in clause 3.1 of the Distribution Code or CitiPower's planning standards. While no incremental cost would be required to implement this option, the impact of a second order contingency would lead to catastrophic consequences.

Under this arrangement, a load of up to 120 MVA would be supplied by not only a single 220/66 kV transformer at WMTS, but also a single 66 kV cable. This is a pre-contingency arrangement solely proposed to prevent automatic load shedding under extreme weather conditions without any plant outage. An outage of either the single 220/66 kV transformer or the single 66 kV cable would cause loss of supply to 6,042 CBD customers. The expected unserved energy at risk under this scenario and the value of customer interruption cost, are shown in the following table.

[384] Cost build up model for demand management at WMTS step change (Attachment 250 to this Revised Regulatory Proposal).
[385] Attachment 249 to this Revised Regulatory Proposal.

Year	2000/11	2011/12	2002/13	2003/14
Hour at Risk (10% PoE)	127.5	204.3	401.9	387.1
MWh at Risk	5,724	9,170	18,046	17,378
Customer Interruption Cost	$8,177,181	$13,099,523	$25,777,941	$24,823,602

Table 6.10 Value of customer interruption cost

The demand management option reduces the load at risk down to levels manageable by distribution load transfers, thus drastically reducing or even nullifying any network exposure.

Option 4

This option is not considered to be a genuine or practicable alternative since CitiPower is not currently aware of any proponents of embedded generation that would be capable of alleviating the constraints identified. It should be noted that embedded generation would be required at specific locations as set out in CitiPower's Annual Planning Reports.

Benefits of demand management solution

The following graphs illustrate the prudency of the demand management solution and quantify the benefits of the proposed demand management program as against the existing situation without demand management. These graphs are based on an average summer. The first graph shows the energy at risk and the customer interruption cost under the existing situation without demand management. The second graph shows the energy at risk and customer interruption cost under the situation with demand management.

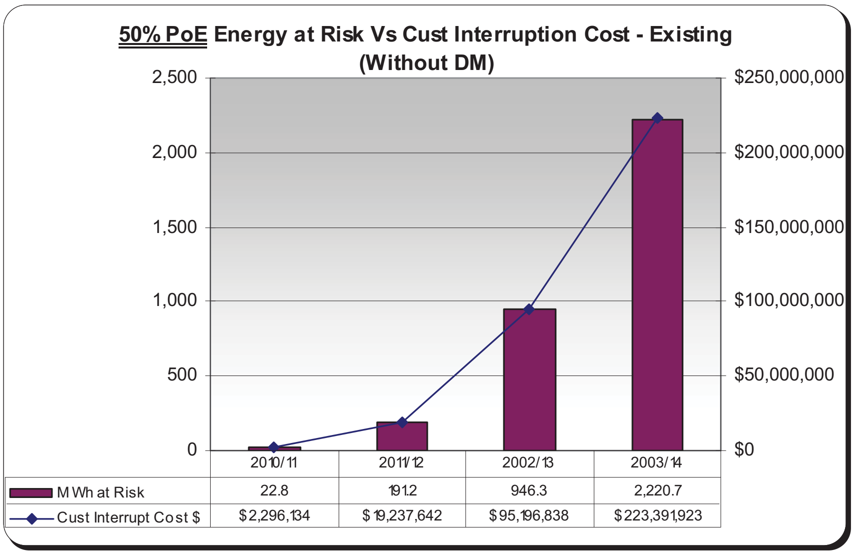

Figure 6.2 Energy at risk and customer interruption cost without demand management

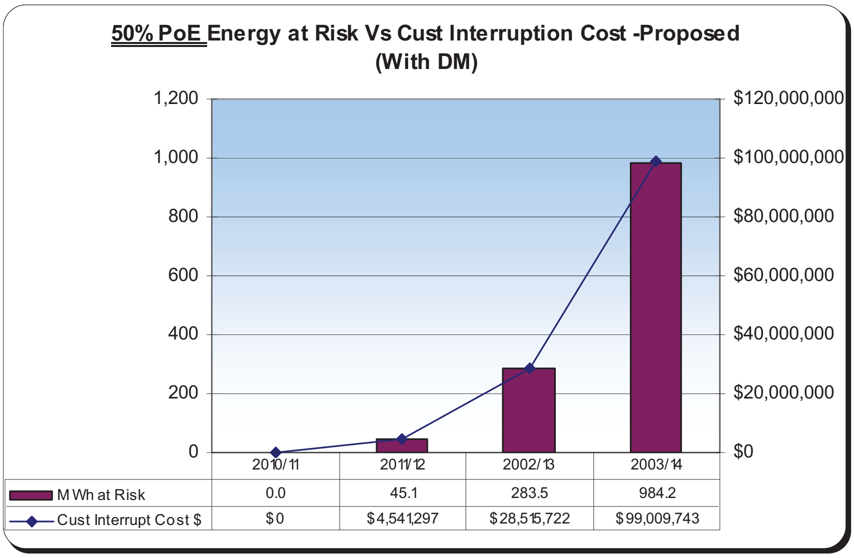

Figure 6.3 Energy at risk and customer interruption cost with demand management

Other issues raised by AER

The AER considered in its Draft Determination that the following aspects of CitiPower's proposal did not support the proposed expenditure:[386]

- demand management costs only being provided by one demand management supplier; and
- the expected reduction in demand by demand management of 10MVA for 2009-10 not being contracted for.

CitiPower only provided costs of one demand management supplier because Energy Response was the only supplier who has shown an interest in submitting a proposal to address the network constraint. CitiPower has invited persons to respond to its need for a demand management solution at WMTS through its Annual Planning Reports. Two suppliers contacted CitiPower regarding its request. However, Energy Response was the only supplier to respond to CitiPower's request with a proposal. The other supplier that contacted CitiPower did not submit an offer to supply the services.

The expected reduction in demand by demand management of 10MVA for 2009-10 has not yet been contracted for because negotiations and commercial discussions have been ongoing on a regular basis with the intention of signing a contract in the second half of 2010.

Other issues raised by Nuttall Consulting

In addition, Nuttall Consulting appeared to be concerned that the demand reductions proposed by CitiPower did not correlate with the information in the TPCR.[387] It was clearly stated in the TCPR that the amount of demand reduction depends on the level of customer uptake.[388]

The table below shows the forecast demand under the 50th percentile probability scenario for the years 2010/11-2013/14 extracted from the TPCR,[389] The table also shows the load at risk

[386] AER, Draft Determination, p212.
[387] Nuttall Consulting, Victorian Capital Expenditure Review, p353.
[388] 2009 TCPR, WMTS 66kV (Attachment 251 to this Revised Regulatory Proposal), p5.
[389] 2009 TCPR, WMTS 66kV (Attachment 251 to this Revised Regulatory Proposal), p7.

after considering the station rating. The figures shown as 'Expected demand reduction by DM (MVA)' are those provided by the demand management supplier to be the guaranteed levels of demand reduction achievable based on their preliminary discussions with potential customers together with their past experience.

Should a demand management option be feasible for the entire load at risk, then the funding required would increase considerably in direct proportion. The remaining shortfall of load at risk is expected to be managed with a combination of contingency actions available at the time and will include any, all or part of those stipulated in the TCPR. However, the level of shortfall between the demand management response delivered by the supplier, and the entire load at risk, as indicated in the table below is expected to be addressed mainly by distribution load transfers for the first three years.

CitiPower notes that any guaranteed reduction in demand and consequently the reduction in load at risk will result in a reduction in the number of days of the station's exposure to risk over the summer period. For example, from the table below, assuming there was a forecast temperature of 35°C for 10 days over the forthcoming 2011 summer period translating to a forecast MD of 509.6 MVA on each of those days, then with a demand reduction of 15 MVA there will be no load at risk and therefore a reduction of 10 days of risk exposure. This would occur without compromising the security level of the entire network.

WMTS 66kV Station N-1 Summer Rating = 497 MVA	2010/11	2011/12	2012/13	2013/14
50 PoE Forecast Summer MD (MVA)	509.6	529.3	554.0	574.1
50 PoE Load at Risk (MVA)	12.6	32.3	57.0	77.1
Expected demand reduction by DM (MVA)	15	20	25	25
50 PoE Shortfall Risk after DM (MVA)	Nil	12.3	32.0	52.1

Table 6.11 Table showing demand reduction scenarios

For the above reasons, CitiPower submits that the AER should accept CitiPower's step change for demand management at WMTS. CitiPower's forecast direct costs of this program are set out in the following table. The proposed forecast step change costs in this table have decreased slightly from those in CitiPower's Initial Regulatory Proposal.

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Demand management step change	2,168	2,576	2,508	-	-	**7,251**

Table 6.12 Step change – demand management at WMTS

6.5.13 Step change – Communications in extreme supply events

6.5.13.1 CitiPower's Initial Regulatory Proposal

In its presentation to the AER on 28 January 2010, CitiPower informed the AER of an additional proposed step change in respect of communications in extreme supply events. In its letter dated 4 March 2010, CitiPower informed the AER that its estimated costs of this step change were $0.2 million per annum ($0.8 million in total).

The step change arose as a result of the ESCV's Extreme Supply Events Decision. Accordingly, it arose after CitiPower submitted its Initial Regulatory Proposal on 30 November 2009.

6.5.13.2 AER's Draft Determination

The AER considered that some Victorian DNSPs may experience a step change in costs as a result of the amendments to the Distribution Code. The AER accepted a step change for Jemena ($2.1 million) and UED ($1.6 million) for communication to customers during outage events.[390] The AER reduced the step changes proposed by Jemena and UED on the basis that it did not consider that there was sufficient certainty regarding an obligation for the Victorian DNSPs to communicate with customers via SMS.

The AER did not comment on CitiPower's proposed step change.

6.5.13.3 CitiPower's response to AER's Draft Determination

The ESCV's Extreme Supply Events Decision was made in response to a request from the Minister for Energy and Resources that it consider and progress a number of regulatory matters relevant to significant energy supply events.[391]

In accordance with the ESCV's Extreme Supply Events Decision, the Distribution Code has been amended to require distributors to:

- comply with the AEMO's Single Industry Spokesperson Protocol and co-operate on the ongoing development of that protocol (clause 8.2);
- provide the Department of Human Services and the Department of Health with street addresses where outages are expected to exceed 24 hours. This information must be provided within 28 hours of a sustained interruption occurring and for every 12 hours afterwards until the sustained interruption has been resolved (clause 5.7.1);
- update their life support registers on an annual basis (clause 5.6.3);
- write to their customers prior to the end of December of each year informing customers of the distributors' role in relation to maintenance of supply, emergencies and restoration after interruptions and their contact details and website address (clause 9.1.2A); and
- provide information on supply interruptions or emergencies on their websites (clause 5.4.1(a)).

The amended Distribution Code took effect from 1 April 2010.[392]

[390] AER Draft Determination, pp197-200.
[391] ESC, Final Amendments to the Electricity Distribution Code and the Energy Retail Code, 24 February 2010 (Attachment 126 to this Revised Regulatory Proposal).
[392] ESCV, Distribution Code (Attachment 127 to this Revised Regulatory Proposal).

Since the amendments to the Distribution Code came into effect, CitiPower has further reviewed its costs resulting from those amendments and, as a result, revised its costs for this step change from those provided to the AER in March 2010. The step change costs are set out in the table below.

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Step change costs for communications in extreme supply events	294	294	294	294	294	1,470

Table 6.13 Communications in extreme supply events step change

The breakdown of these costs is provided as an attachment to this Revised Regulatory Proposal.[393] Since there are synergies for CitiPower and Powercor Australia in complying with the new requirements of the Distribution Code, the total costs of complying with this step change have been calculated and 70 per cent of those costs have been allocated to Powercor Australia with the remaining 30 per cent being allocated to CitiPower based on share of customers.

CitiPower observes that the total of this step change relates to the new requirements in respect of communication in extreme supply events that are included in the Distribution Code as set out above. That is, no component of this step change cost relates to SMS communication with customers.

It is necessary for the AER to allow this step change for CitiPower because the costs associated with the step change satisfy the opex criteria, as the AER has recognised in allowing a similar step change for Jemena and UED. CitiPower considers its proposed costs for this step change are consistent with those which the AER approved for Jemena and UED.

6.5.14 Step change – Outcomes monitoring and compliance

6.5.14.1 AER's Draft Determination

In Chapter 21 of its Draft Determination, the AER proposed the introduction of an outcomes monitoring program to replace the existing annual reporting requirements. The AER set out:

- the monitoring framework which it intends to establish to monitor the consistency of the Victorian DSNPs with the AER's Final Determination, and the service levels delivered to customers; and
- the information the AER proposes to collect annually to assess the Victorian DNSPs' compliance with the Final Determination. The AER proposed that this information would be collected annually through the issuing of a RIN under section 28F(1)(a) of the NEL.

The proposed outcomes monitoring program represents a considerable expansion of the reporting requirements under the existing regulatory framework of the ESCV. The present

[393] Attachment 128 to this Revised Regulatory Proposal.

arrangements focus on the provision of aggregated financial information available through the regulatory accounts, reliability reporting, generic network statistics and reporting of volume data (energy, demand and customer numbers) and the Annual Planning Report.

The AER's outcomes monitoring program, as CitiPower understands it, requires in addition to what is provided today:

- the provision of the condition or health index of each zone substation transformer and major item of switchgear;
- individual distribution feeder information;
- for each asset category, the forecast volume of replacement and refurbishment to be undertaken;
- provision of the number of customer connection jobs by connection category;
- plans, expenditure and actual activities against programs to reduce bushfire risk;
- asset failure rates; and
- annual five year forecasts of a variety of capex categories.

6.5.14.2 CitiPower's response to AER's Draft Determination

As the AER would be aware through the information exchange process that followed the lodging of CitiPower's Initial Regulatory Proposal, the information sought above is not readily available from within CitiPower's systems. Where that information was provided to the AER during the information exchange process, it was often the result of approximations or assumptions or involved the extensive use of internal resources to prepare.

While approximations or assumptions may be suitable for a 'one off' request, it is not suitable as a process for the longer term and is unlikely to result in the quality of information the AER expects to receive to implement its outcomes monitoring framework. Further, CitiPower cannot continue to devote up to ten full time resources to collecting information not used internally within CitiPower.

The requirement for annual five yearly forecasts for capex appears particularly onerous. This equates effectively to an annual price reset process for DNSPs which will require extensive resourcing across the Network, Finance and Regulation divisions within CitiPower.

Based on CitiPower's previous regulatory experience, it expects that the high level listing of information in the Draft Determination will not be all that is required to satisfy the AER's outcomes monitoring framework. Experience has demonstrated through the RIN process associated with the current price reset that final RINs have deviated substantially from draft RINs and over time, further information has been sought that has not been listed in any RIN.

Accordingly, the outcomes monitoring program will not be costless and will require augmentation of CitiPower's existing reporting systems and resourcing.

CitiPower also expects that because information is now being sought through a RIN, the collection and reporting of that information will require greater due diligence than it has exercised under the existing reporting arrangements. This is because, under section 28R of the NEL, the provision of false or misleading information is punishable through substantial fines. As a consequence CitiPower will be required to periodically audit the information being provided and subject any information being provided to the AER to legal review.

CitiPower has reviewed the Previous Distribution Determinations and finds no reference to the outcomes monitoring program. This is perplexing given the creation of a national regulatory framework was intended to create consistency across jurisdictions, particularly in relation to the information being collected.

While CitiPower does not object to the imposition of the AER's proposed outcomes monitoring framework provided it receives a commensurate expenditure allowance to enable it to comply with that framework, CitiPower reserves its rights in respect of the making of the RIN, including its right to raise any matters in the consultation process on the RIN.

CitiPower has forecast the costs associated with managing the AER's proposed outcomes monitoring program. The expenditure associated with this change in reporting requirements is ongoing expenditure and is not reflected in CitiPower's 2009 base year opex. This expenditure relates to IT costs of developing programs to capture the AER's outcomes monitoring and compliance requirements, costs of CitiPower's regulatory team and its Network group in preparing responses to the RIN, costs of auditing the information being provided to the AER and costs of legal reviews undertaken of that information. The break down of these costs (including a detailed breakdown of IT costs) is set out in an attachment to this Revised Regulatory Proposal.[394] The total costs have been apportioned evenly between CitiPower and Powercor Australia.

Accordingly, CitiPower proposes the following step change for that expenditure:

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Step change costs for outcomes monitoring and compliance	665	60	60	60	60	905

Table 6.14 Step change - incremental impact of increase in costs associated with outcomes monitoring and compliance

6.5.15 Step change – Tariff assignment requirements

6.5.15.1 AER's Draft Determination

Appendix G of the AER's Draft Determination contains the AER's proposed procedures for assigning or reassigning customers to tariff classes. Clause 6 of the procedure requires Victorian DNSPs to notify the customer concerned in writing of the tariff class to which the customer has been assigned or reassigned prior to the assignment or reassignment occurring.[395]

[394] Cost build up model for outcomes monitoring and compliance step change (Attachment 130 to this Revised Regulatory Proposal).

[395] AER, Draft Determination, Appendix G, p21.

6.5.15.2 CitiPower's response to AER's Draft Determination

Currently, the analogous regulatory obligation on Victorian DNSPs is limited to notifying customers of the distribution tariff to which the distribution customer has been reassigned, prior to the reassignment occurring.[396] That is, unlike the AER's proposal it does not require DNSPs to notify customers of the tariff class to which the customer has been assigned prior to the assignment occurring. This issue is discussed in further detail in Chapter 3 of this Revised Regulatory Proposal which deals with control mechanisms for standard control services.

If the AER retains this change to the current obligation in its Final Determination, CitiPower considers that the AER must compensate it for the additional costs it will incur. Accordingly, CitiPower has proposed a step change for that expenditure.

CitiPower considers that, if the AER does not alter this requirement in the procedures for assigning or reassigning customers to tariff classes, CitiPower's forecast step change would:

- properly be categorised as being triggered by a change in CitiPower's regulatory obligations, as CitiPower's obligations under the ESCV's 2006-10 EDPR do not require this expenditure; and
- reasonably reflect the efficient costs a prudent operator in CitiPower's circumstances would require to achieve the opex objectives, in particular the requirement in clause 6.5.6(a)(2) to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

Accordingly, CitiPower proposes the following step change for that expenditure:

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Tariff assignment step change	449	155	155	155	155	**1,069**

Table 6.15 Tariff assignment step change

CitiPower observes that the AER will not need to allow CitiPower this step change if the AER accepts its proposal described in Chapter 3 of this Revised Regulatory Proposal to amend clause 6 of the AER's proposed procedures for assigning and reassigning customers to tariff classes.

6.5.16 Step change - transmission-related costs

In Chapter 3 of this Revised Regulatory Proposal, CitiPower proposed that the AER should include a new term in each of the WAPC and side constraint formulas to address transmission-related costs.

In preparing this Revised Regulatory Proposal, CitiPower has proceeded on the basis that the AER will accept its proposal to include new terms in the WAPC and side constraint formula to address transmission-related costs. Accordingly, it has not included this expenditure in its forecast opex.

However, as set out in Chapter 3, CitiPower submits that if the AER rejects its proposed WAPC or side constraint terms (or both of them) regarding transmission-related costs, the

[396] Clause 2.1.20 of the ESCV's 2006-10 EDPR (Attachment 32 to this Revised Regulatory Proposal).

AER will have to make an allowance in opex for the recovery of those costs. This expenditure is required to achieve the opex objectives under clause 6.5.6(a) of the Rules. These costs would be required to be incurred by an efficient and prudent operator to achieve the opex objectives.

6.6 CitiPower's Revised Regulatory Proposal

CitiPower has amended its Initial Regulatory Proposal and prepared this Revised Regulatory Proposal to be consistent with the AER's Draft Determination in respect of the following:

- the AER's adjustment to base year costs to remove regulatory reset costs;[397]
- the AER's decision to roll forward the 2009 base year costs to 2010 by inflating the 2009 costs by the change in costs assumed by the ESCV in determining the benchmark opex allowance for 2009 and 2010 in its 2006-10 EDPR;[398]
- the AER's decision in respect of CitiPower's proposed step change for self insurance;[399]
- the AER's decision in respect of CitiPower's proposed step change for climate change;[400]
- the AER's decision in respect of CitiPower's proposed step change for compliance with the Electricity Safety Management Regulations;[401]
- the AER's decision in respect of CitiPower's proposed step change for the national framework for distribution network planning and expansion;[402]
- the AER's decision in respect of CitiPower's proposed step change in respect of the customer charter;[403] and
- the AER's decision to include a step change for CitiPower in respect of regulatory submission costs.[404]

CitiPower has revised its Initial Regulatory Proposal and prepared this Revised Regulatory Proposal:

- having regard to its final audited regulatory accounts;
- to make adjustments for movements in provisions;
- to adjust base year opex to deduct CitiPower's distribution licence fee of $161,950;
- to make a GSL allowance for the 2011-15 regulatory control period based on an average of its actual payments over 2005-09 with a customer growth factor applied to the average GSL payment value;
- to alter its proposed adjustment in respect of capitalisation to that set out above;
- to alter its proposed amount of debt raising costs to that set above;

[397] AER, Draft Determination, p243.
[398] AER, Draft Determination, p246.
[399] AER, Draft Determination, Appendix M.
[400] AER, Draft Determination, Appendix L, p186.
[401] AER, Draft Determination, Appendix L, p159.
[402] AER, Draft Determination, Appendix L, p197;
[403] AER, Draft Determination, Appendix L, p203.
[404] AER, Draft Determination, Appendix L, p208.

- to adjust its base opex for 2009 to include all superannuation costs and apply a step change for the years 2011-15 in respect of its defined benefit and accumulation superannuation schemes;
- to propose an additional step change set out above as a result of the Commonwealth Government's announcement in respect of the superannuation guarantee levy;
- to revise its proposed step change in respect of insurance to be based on a 15 per cent increase on the 2009 insurance premium reported in its regulatory accounts pending determination of the premium for 2010/11 on or around 30 September 2010;
- to clarify and alter its proposed step change in respect of compliance with the 2010 Line Clearance Regulations to that set out above;
- to revise its proposed step change amount in respect of demand management at WMTS to that set out above;
- to include its proposed step change set out above for complying with the new requirements of the Distribution Code in respect of communication in extreme supply events;
- to propose an additional step change set out above for compliance with the AER's outcomes monitoring framework that is foreshadowed in Chapter 21 of its Draft Determination;
- to propose an additional step change set out above for compliance with the AER's proposed tariff assignment requirements in Appendix G of its Draft Determination;
- to apply scale escalation as set out in Chapter 7 of this Revised Regulatory Proposal; and
- to apply real cost escalators as set out in Chapter 8 of this Revised Regulatory Proposal.

CitiPower's Regulatory Proposal in respect of opex is otherwise that set out in its Initial Regulatory Proposal.

The key assumptions which underlie the proposed opex forecast as set out and included in CitiPower's building block proposal are listed in Appendix 1.1 to this Revised Regulatory Proposal.

The table below shows the calculation of CitiPower's revised proposed 2010 base opex the 2010-15 regulatory control period.

	($'000, $2010)
2009 O&M per Regulatory Accounts	36,587
Provision adjustments	981
Licence fee	(164)
ATO audit	0
GSLs	(2)
Superannuation	0
Price Review	(893)
2010 Benchmark Efficiency	641
Total	**37,149**

Table 6.16 CitiPower's revised proposed 2010 base opex

The table below shows CitiPower's revised proposed forecast total operating and maintenance costs the 2010-15 regulatory control period.

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
2010 Base O&M	37,149	37,149	37,149	37,149	37,149	**185,747**
Step changes (excluding margins, escalation & overheads)	11,058	9,843	10,184	8,717	9,198	**49,001**
Change in overhead transfers (excluding margins and escalation)	(1,154)	(1,267)	(1,407)	(1,094)	(677)	**(5,599)**
Input escalation (on above costs)	1,021	2,178	3,068	3,622	4,386	**14,276**
Scale escalation (on above costs)	407	843	1,265	1,817	2,401	**6,733**
Margins (on above costs)	2,857	2,987	3,091	3,213	3,353	**15,501**
Total	**51,339**	**51,735**	**53,351**	**53,423**	**55,811**	**265,659**

Table 6.17 CitiPower's revised proposed forecast total opex

The following table shows CitiPower's proposed step changes, including escalation, margins and overheads where relevant.

	$'000 ($2010)					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Direct costs						
Customer Charter	318	-	-	-	-	**318**
AEMC Framework Distribution Planning	633	478	604	483	522	**2,720**
Demand Management WMTS	2,168	2,576	2,508	-	-	**7,251**
Communications in extreme supply events	294	294	294	294	294	**1,470**
Vegetation clearance (compliance with Line Clearance Regulations)	4,175	3,723	3,692	3,703	3,902	**19,194**
Insurance	132	132	132	132	132	**661**
Tariff assignment	449	155	155	155	155	**1,069**
Demand incentive allowance	200	200	200	200	200	**1,000**
GSL payments	16	16	16	16	16	**81**
Regulatory submission costs	-	-	64	893	761	**1,717**
Superannuation	155	185	259	388	589	**1,577**
Outcomes monitoring and compliance	665	60	60	60	60	**905**
Overhead transfers	(1,154)	(1,267)	(1,407)	(1,094)	(677)	**(5,599)**
Debt Raising Costs	1,853	2,025	2,200	2,392	2,568	**11,038**
Total	**9,905**	**8,577**	**8,777**	**7,622**	**8,521**	**43,402**
Escalation						
Customer Charter	7	-	-	-	-	**7**
AEMC Framework Distn Planning	22	40	76	77	101	**316**
Demand Management WMTS	48	120	154	-	-	**322**
Communications in extreme supply events	7	14	18	21	25	**84**
Vegetation clearance (compliance with Line Clearance Regulations)	-	-	-	-	-	**-**

Insurance	-	-	-	-	-	**-**
Tariff assignment	-	-	-	-	-	**-**
Demand incentive allowance	-	-	-	-	-	**-**
GSL payments	0	1	1	1	1	**4**
Regulatory submission costs	-	-	4	64	64	**132**
Superannuation	-	-	-	-	-	**-**
Outcomes monitoring and compliance	-	-	-	-	-	**-**
Overhead transfers	-	-	-	-	-	**-**
Debt Raising Costs	-	-	-	-	-	**-**
Total	**85**	**174**	**253**	**163**	**191**	**865**
Overheads						
Customer Charter	-	-	-	-	-	**-**
AEMC Framework Distn Planning	-	-	-	-	-	**-**
Demand Management WMTS	-	-	-	-	-	**-**
Communications in extreme supply events	-	-	-	-	-	**-**
Vegetation clearance (compliance with Line Clearance Regulations)	767	667	628	672	768	**3,501**
Insurance	-	-	-	-	-	**-**
Tariff assignment	-	-	-	-	-	**-**
Demand incentive allowance	-	-	-	-	-	**-**
GSL payments	-	-	-	-	-	**-**
Regulatory submission costs	-	-	-	-	-	**-**
Superannuation	-	-	-	-	-	**-**
Outcomes monitoring and compliance	-	-	-	-	-	**-**
Overhead transfers	-	-	-	-	-	**-**
Debt Raising Costs	-	-	-	-	-	**-**

Total	**767**	**667**	**628**	**672**	**768**	**3,501**
Margins						
Customer Charter	-	-	-	-	-	**-**
AEMC Framework Distribution Planning	-	-	-	-	-	**-**
Demand Management WMTS	-	-	-	-	-	**-**
Communications in extreme supply events	-	-	-	-	-	**-**
Vegetation clearance (compliance with Line Clearance Regulations)	46	41	39	42	48	**216**
Insurance	-	-	-	-	-	**-**
Tariff assignment	-	-	-	-	-	**-**
Demand incentive allowance	-	-	-	-	-	**-**
GSL payments	-	-	-	-	-	**-**
Regulatory submission costs	-	-	-	-	-	**-**
Superannuation	-	-	-	-	-	**-**
Outcomes monitoring and compliance	-	-	-	-	-	**-**
Overhead transfers	-	-	-	-	-	**-**
Debt Raising Costs	-	-	-	-	-	**-**
Total	**46**	**41**	**39**	**42**	**48**	**216**
Total						
Customer Charter	326	-	-	-	-	**326**
AEMC Framework Distn Planning	655	518	680	560	623	**3,036**
Demand Management WMTS	2,216	2,695	2,662	-	-	**7,573**
Communications in extreme supply events	301	308	312	315	319	**1,554**
Vegetation clearance (compliance with Line Clearance Regulations)	4,988	4,430	4,358	4,417	4,717	**22,910**
Insurance	132	132	132	132	132	**661**

Tariff assignment	449	155	155	155	155	**1,069**
Demand incentive allowance	200	200	200	200	200	**1,000**
GSL payments	17	17	17	17	18	**86**
Regulatory submission costs	-	-	68	956	825	**1,849**
Superannuation	155	185	259	388	589	**1,577**
Outcomes monitoring and compliance	665	60	60	60	60	**905**
Overhead transfers	(1,154)	(1,267)	(1,407)	(1,094)	(677)	**(5,599)**
Debt Raising Costs	1,853	2,025	2,200	2,392	2,568	**11,038**
Total	**10,802**	**9,458**	**9,697**	**8,499**	**9,529**	**47,984**

Table 6.18 CitiPower's proposed step changes (including escalation, margins and overheads)

7. SCALE ESCALATION

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to section 7.5.5 of, and Appendix J to, the AER's Draft Determination regarding CitiPower's proposed scale escalation of its opex forecast.

7.1 Summary of key points

While CitiPower accepts the AER's use of a composite growth factor based on physical metrics as a network growth driver, CitiPower contends that growth in the **number of zone substations** is not a reasonable indicator of growth in operating and maintenance activity levels resulting from network growth. Rather, CitiPower considers that a network growth escalator based on the simple average of growth in line length, transformers and **installed zone substation capacity** is appropriate.

CitiPower does not contest the AER's decision to reject its work volume escalator and apply a network growth escalator to the relevant capex categories instead.

Noting the AER's acceptance of its customer growth escalator in the Draft Determination, CitiPower includes in this Revised Regulatory Proposal an updated customer growth escalator, which reflects current customer growth forecasts based on more recent macro economic data.

CitiPower agrees with the AER's rejection of the escalation of the following: 'Emergency faults (meters)', 'Meters, timeswitches & services maintenance', 'Metering communications' and 'New connections' (function codes 311, 430, 435 and 852). CitiPower has also adopted the AER's economies of scale adjustment of 50 per cent for the 'Quality audits' opex category (function code 482).

However, CitiPower maintains that its remaining economies of scale adjustments, and its application of these adjustments, are reasonable.

CitiPower submits that the AER should not make a downward adjustment to its opex due to the reliability and quality maintained capex proposed in its Revised Regulatory Proposal. CitiPower considers that the approach adopted by the AER to determining the capex/opex trade-off is unreasonable and results in a significant understatement of the opex that CitiPower, acting efficiently and prudently, will require in the next regulatory control period. In particular, the AER's approach fails to take into account the increasing average asset age of CitiPower's network, which implies that CitiPower's opex should be expected to increase (rather than decrease) in the next regulatory control period. Acting conservatively, however, CitiPower has not included any amounts in this Revised Regulatory Proposal to reflect the increase in opex it anticipates will arise in the next regulatory control period given its proposed level of capex.

7.2 Rule requirements

CitiPower applies scale escalators (and makes economies of scale adjustments) to input cost escalated opex forecasts for the 2011-15 regulatory control period. Accordingly, the provisions of the Rules governing the total opex forecast (detailed in Chapter 6 of this Revised Regulatory Proposal) apply. Broadly, the total opex forecast must reasonably reflect the opex criteria.

7.3 CitiPower's Initial Regulatory Proposal

7.3.1 Scale escalators

Scale escalation of opex forecasts is required to allow for the additional costs associated with operating and maintaining a growing network.

In its Initial Regulatory Proposal, CitiPower applied one of three proposed scale escalators (or scale drivers) to a number of opex categories that were identified as being driven by growth.[405] The scale escalators applied were:

- network growth – to take into account growth in the size of the distribution network. CitiPower's network growth escalator was determined based on the undepreciated RAB;
- work volume – to take into account changes in the volume of capital and maintenance activity on the network; and
- customer growth – to take into account changes in customer numbers.

CitiPower engaged an independent expert, SKM, to examine the derivation of the scale escalators. SKM was satisfied with the calculation methodology utilised for each escalator.[406]

The values of the scale escalators reflected in the Initial Regulatory Proposal are set out in Table 7.1 below.

	Cumulative %					
	2010	2011	2012	2013	2014	2015
Network growth	2.5	5.7	9.0	12.4	16.0	19.7
Work volume	4.3	22.4	25.1	27.6	30.8	32.3
Customer growth	1.8	3.6	5.3	7.1	8.9	10.9

Table 7.1 Scale escalators applied in CitiPower's Initial Regulatory Proposal

7.3.2 Economies of scale adjustments

To account for the fact that opex does not grow in direct proportion to the growth in the network,[407] CitiPower made economies of scale adjustments to reduce the impact of the scale escalators (identified in Table 7.1 above) on the total opex forecast.

The economies of scale adjustments made by CitiPower were determined by SKM, adopting the approach previously used by ElectraNet and ETSA.[408] SKM modified the adjustments

405 Initial Regulatory Proposal, pp160-1.

406 SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), pp9-10.

407 Opex does not grow in direct proportion to the growth in the network (including physical network growth, growth in work volume and customer growth) because economies of scale allow DNSPs to achieve efficiencies resulting from a larger network.

408 SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11.

to five categories of opex to reflect what SKM considered to be '*a more accurate and conservative reflection of the underlying cost pressure*'.[409]

The economies of scale adjustments reflected in the Initial Regulatory Proposal are set out in Table 7.2 below. The percentages set out in Table 7.2 represent the percentage reduction to the scale escalation amount for the identified opex category to account for economies of scale.[410]

7.3.3 Application of the scale escalators and economics of scale adjustments

As noted, one of the escalators set out in Table 7.1 above was applied to each opex activity that was identified by CitiPower as being driven by scale. The application of the scale escalators is shown in Table 7.2 below.

The escalators were applied to opex forecasts that had already been escalated for expected increases in input costs.

CitiPower engaged SKM to review the application of the scale escalators. SKM found that the application of the scale escalators (set out in Appendix A to SKM's report) was reasonable.[411] SKM supported the approach of applying scale escalators to input cost escalated forecasts.[412]

SKM also reviewed the application of the economies of scale adjustments to the opex categories.[413] SKM found that CitiPower's application (also set out in Appendix A to SKM's report) was reasonable.[414]

Function code	Operating and maintenance activity	Scale escalator	Economies of scale adjustment
Network operating & maintenance activities			
309	Emergency faults - overhead	Network growth	5%
310	Emergency faults - underground	Network growth	5%
311	Emergency faults - meters	Customer growth	5%
312	Emergency faults - protection & control	Network growth	5%

[409] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11. SKM increased the economies of scale adjustment applied to opex under function codes 313 and 450 ('Emergency faults – public lighting' and 'Public lighting maintenance') from 5 per cent to 90 per cent to reflect the fact that CitiPower's network was not expanding substantially and most new customer connections would be urban consolidation and within areas already served by street lighting. SKM also increased the economies of scale adjustment made to opex under function codes 400, 410 and 426 ('Vegetation control', 'Insulator washing' and 'Bushfire mitigation') from five per cent to 75 per cent because much of the growth would be within the existing network. CitiPower notes that SKM refers to economies of scale 'factors'. The economies of scale adjustment is 100 per cent minus the economies of scale factor referred to by SKM.

[410] The figures in Table 7.2 are 100 per cent minus the economies of scale 'factors' identified by SKM. The adjustments have been represented in this way in the Revised Regulatory Proposal so that they are consistent with the AER's representation them.

[411] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

[412] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), pp1, 13.

[413] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

[414] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

Function code	Operating and maintenance activity	Scale escalator	Economies of scale adjustment
313	Emergency faults - public lighting	Customer growth	90%
314	Faults & emergency work	Network growth	5%
315	Fault investigation	Network growth	5%
316	ZSS plant routine & defect maintenance	Network growth	5%
317	ZSS breakdown maintenance	Network growth	5%
318	Distribution system plan routine & defect maintenance	Network growth	5%
319	Distribution system plant breakdown maintenance	Network growth	5%
321	System planning contingencies	Network growth	75%
322	System operations	Network growth	50%
325	Roads management bill	Work volume	5%
330	Overhead line maintenance	Network growth	5%
333	Conductor clearance (ops)	Network growth	5%
335	Voltage complaints	Network growth	5%
336	TV interference (TVI) complaint investigation	Network growth	75%
350	High voltage installation maintenance	Network growth	5%
380	Asset inspection	Network growth	5%
381	Pole defect management	Network growth	5%
383	Safety compliance	Network growth	75%
400	Vegetation control	Network growth	75%
410	Insulator washing	Network growth	75%
425	Environment management	Network growth	90%
426	Bushfire mitigation	Network growth	75%
430	Meters, timeswitches & services- maintenance	Customer growth	5%
435	Metering communications - maintenance & operating	Customer growth	5%
440	Underground cable locations	Network growth	5%
442	Underground cable maintenance	Network growth	5%
450	Public lighting maintenance	Customer growth	90%
477	Project establishment works	Customer growth	50%
478	Customer supply negotiations	Customer growth	50%
482	Quality audits	Work volume	5%
483	Thermovision	Network growth	5%
484	Quality investigations	Network growth	5%

Function code	Operating and maintenance activity	Scale escalator	Economies of scale adjustment
485	Network logging monitoring	Network growth	90%
486	Maintenance research and development	Network growth	90%
487	Technical standards and innovation	Network growth	90%
488	OCEI reporting	Network growth	90%
490	Property - operating & maintenance	Network growth	90%
492	Substation property maintenance	Network growth	5%
500	General and administration	Work volume	90%
505	Quality accreditation	Network growth	90%
506	Engineering & technical services	Network growth	75
512	Recruitment	Work volume	75%
516	Health & safety	Work volume	75%
525	Training	Work volume	90%
536	Motor vehicle and plant	Work volume	75%
590	Computer systems	Work volume	75%
595	Voice communications	Work volume	75%
596	Data communications	Work volume	75%
600	CitiPower / Powercor works	Work volume	75%
635	Salary expenditure	Network growth	75%
640	Cust serv: techn supp	Customer growth	75%
682	GSL payment	Customer growth	5%
800	Revenue - customer connections	Customer growth	5%
802	Revenue maintenance	Customer growth	5%
852	New connections	Customer growth	5%
999	Capital data take on Stores recovery	Network growth	75%
Meter Data services			
	FRC/MDS/CIS	Customer growth	90%
	FRC/MDS/CIS - AMI	Customer growth	90%
	Meter Data Management	Customer growth	90%
Billing & revenue collection			
	Billing & Rev Collection	Customer growth	5%
Customer service			
	Customer service	Customer growth	50%

Function code	Operating and maintenance activity	Scale escalator	Economies of scale adjustment
Other			
	Network finance	Network growth	90%
	HR Corporate	Work volume	90%
	GIS/OMS/SCADA	Network growth	75%
	Infrastructure	Work volume	90%

Table 7.2 Application of scale escalators and economies of scale adjustments in CitiPower's Initial Regulatory Proposal

7.4 AER's Draft Determination

The AER did not accept CitiPower's proposed scale escalation of its opex forecasts.

In place of the scale escalators proposed by each of the Victorian DNSPs, the AER proposed two growth drivers:[415]

- a network growth driver, equal to the simple average of the annual growth in line length, the number of distribution transformers and the number of zone substations over the forthcoming regulatory control period; and
- the annual growth in customer numbers over the forthcoming regulatory control period.

The AER increased the economies of scale adjustment proposed by CitiPower for some categories of expenditure[416] and removed all proposed scale escalation from other categories.[417] The AER also stated that it made adjustments to reflect SKM's recommendations regarding the economies of scale adjustments to be made.[418]

The AER indicated in its Draft Determination that an adjustment should be made to CitiPower's total opex forecast to reflect its proposed increase in reliability and quality maintained capex (i.e. to reflect the capex/opex trade-off).[419] The AER reduced CitiPower's proposed opex by adopting the approach to capex/opex trade-off outlined by PB in support of the AER's South Australian Draft Determination.[420]

The AER's rejection of CitiPower's proposed scale escalators and economies of scale adjustments, as well as the AER's approach to the capex/opex trade-off, are set out in more detail below.

415 AER, Draft Determination, p252.
416 AER, Draft Determination Appendices, Appendix J, pp100-103; AER, spreadsheet titled 'CP_PAL_Scale_Opex_Economies of Scale_Draft_Decision' (provided to CitiPower by the AER by email on 24 June 2010).
417 AER, Draft Determination Appendices, Appendix J, pp101-103; AER, spreadsheet titled 'CP_PAL_Scale_Opex_Economies of Scale_Draft_Decision' (provided to CitiPower by the AER by email on 24 June 2010).
418 AER, Draft Determination Appendices, Appendix J, p100.
419 AER, Draft Determination Appendices, Appendix J, pp105-107.
420 AER, Draft Determination Appendices, Appendix J, pp105-7.

7.5 CitiPower's response to the AER's Draft Determination

7.5.1 Scale escalators

7.5.1.1 Summary

While CitiPower accepts the AER's use of a composite growth factor based on physical metrics as a network growth driver, CitiPower contends that growth in the **number of zone substations** is not a reasonable indicator of growth in operating and maintenance activity levels resulting from network growth. Rather, CitiPower considers that a network growth escalator based on the simple average of growth in line length, transformers and **installed zone substation capacity** is appropriate.

CitiPower does not contest the AER's decision to reject its work volume escalator and apply a network growth escalator to the relevant capex categories instead.

Noting the AER's acceptance of its customer growth escalator in its Draft Determination, CitiPower includes in this Revised Regulatory Proposal an updated customer growth escalator, which reflects current customer growth forecasts based on more recent macro economic data.

Each of these matters is discussed in further detail below.

7.5.1.2 Network growth

CitiPower accepts the AER's decision to adopt physical metrics as a driver for network growth. Further, CitiPower accepts the AER's decision to calculate the network growth driver by taking the simple average of the physical metrics.

However, CitiPower does not accept the AER's selection of physical metrics. While CitiPower accepts that growth in line length and growth in the number of distribution transformers may be appropriate measures of network growth, CitiPower does not consider growth in the number of zone substations to be a reasonable driver of growth.

The growth in the number of zone substations does not provide an indication of the growth in the operating and maintenance activity levels resulting from growth in the network. In a review of the AER's Draft Determination (requested by CitiPower following the release of the Draft Determination), SKM noted that the operating and maintenance costs associated with zone substations are closely related to the size and quantity of the equipment contained therein and this can vary significantly between zone substations.[421] SKM observed that:[422]

> *'Rural zones are frequently only single transformer, whereas urban and CBD zones often have 3, 4 or more transformers, and are frequently developed in a "staged" manner whereby additional transformers are installed over time. The number of busbars, circuit breakers, protection relays and other items of equipment that drive opex costs are also generally proportional to the number of transformers.'*

[421] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p3.

[422] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), pp3-4.

Another independent expert engaged by CitiPower following the release of the Draft Determination, PB, reached the same view. PB noted that:[423]

> *'the use of the number of zone substations is likely to be a less accurate indicator of growth in opex costs than aggregate capacity as typically, operational costs, inspection costs and routine/condition/emergency related maintenance is undertaken based on both the number of discrete pieces of plant and equipment used within zone substations, and to a lesser extent the size (which may be considered a measure of the importance of the plant). Practically, it is reasonable to expect a zone substation with four transformers and associated volumes of sub-transmission and HV switchgear will require substantially more operation and maintenance opex compared with a single transformer site.'*

By contrast, SKM noted that 'per substation' items (e.g. batteries) would generally comprise only a small proportion of the zone substation opex costs.[424]

Further, contrary to the AER's suggestion that the AER's approach is broadly consistent with the approach adopted in the South Australian Final Determination,[425] CitiPower considers that moving from a composite network growth factor based on line length, transformers and **installed zone substation capacity** (as was used in the South Australian Final Determination[426]) to a composite network growth factor based on line length, transformers and the **number of zone substations** is significant. First, as discussed above, the growth in the number of zone substations does not provide an indication of growth in operating and maintenance activity levels resulting from growth in the network. Second, while PB, an independent expert engaged by the AER, approved the use of growth in installed zone substation capacity as an appropriate driver of network growth,[427] CitiPower is not aware of any expert opinion supporting the use of the number of zone substations as a measure of network growth.

CitiPower therefore proposes in this Revised Regulatory Proposal a network growth escalator equal to the simple average of growth in line length, growth in the number of distribution transformers and growth in installed zone substation capacity. The determination of the network growth escalator applied by CitiPower is set out in Table 7.3 below.

	Level and Growth %					
	2010	2011	2012	2013	2014	2015
Lines (km)[428]	7,489	7,729	7,992	8,263	8,539	8,828
Lines growth (year on year)		3.21%	3.40%	3.39%	3.34%	3.39%
Distribution transformers	4,531	4,613	4,697	4,782	4,869	4,957

[423] PB, Letter re Application of network growth scale escalators for opex forecasts, 2 July 2010 (Attachment 134 to this Revised Regulatory Proposal), p2.
[424] SKM, *Review* of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p4.
[425] AER, Draft Determination Appendices, Appendix J, p95.
[426] AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), pp212-4; AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), pp120-2.
[427] PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015, November 2009 (Attachment 135 to this Revised Regulatory Proposal), pp365-6.
[428] See Revised Regulatory Templates 6.1.

Distribution transformers growth (year on year)		1.81%	1.82%	1.81%	1.82%	1.81%
Installed substation capacity	2,458	2,513	2,568	2,613	2,714	2,799
Installed substation capacity growth (year on year)		2.24%	2.19%	1.75%	3.86%	3.13%
Average growth – bottom up (simple average)	3.22%	2.42%	2.47%	2.32%	3.01%	2.78%

Table 7.3 Determination of the network growth escalator applied in CitiPower's Revised Regulatory Proposal

7.5.1.3 Work volume

The AER rejected CitiPower's approach to determining a work volume escalator on the basis it was circular.[429]

While SKM, in its review of the AER's Draft Determination, disputes the AER's conclusion that CitiPower's proposed work volume growth driver is circular and suggests that the AER undertake a proper review of the escalator,[430] CitiPower accepts the AER's decision not to use a work volume escalator and to apply a network growth escalator to the relevant categories of opex instead.[431]

7.5.1.4 Customer growth

In its Draft Determination, the AER acknowledged that, in addition to size of the physical network, opex (specifically, opex relating to customer service and associated corporate services) can be driven by the number of customers.[432] The AER accepted the customer growth escalator proposed by CitiPower.[433]

The customer growth escalator applied in CitiPower's Revised Regulatory Proposal has been updated to reflect NIEIR's current forecasts of customer growth (discussed in Chapter 4).

7.5.2 Economies of scale adjustment

CitiPower agrees with the AER's rejection of the escalation of the following: 'Emergency faults (meters)', 'Meters, timeswitches & services maintenance', 'Metering communications' and 'New connections' (function codes 311, 430, 435 and 852). CitiPower has also adopted the AER's economies of scale adjustment of 50 per cent for the 'Quality audits' opex category (function code 482).

However, CitiPower maintains that its remaining economies of scale adjustments, and its application of these adjustments, are reasonable.

[429] AER, Draft Determination Appendices, Appendix J, p93.
[430] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), pp4-7.
[431] AER, Draft Determination Appendices, Appendix J, pp94 (including footnote 39), 98 (Table J.7); AER, spreadsheet titled 'CP_PAL_Scale_Opex_Economies of Scale_Draft_Decision' (provided to CitiPower by the AER by email on 24 June 2010).
[432] AER, Draft Determination Appendices, Appendix J, p94.
[433] AER, spreadsheet titled 'CP PC_AER_Scale_Opex_Draft_Decision' (provided to CitiPower by the AER by email on 7 June 2010).

As noted above, the adjustments proposed in the Initial Regulatory proposal were considered reasonable by an independent expert, SKM.[434] In addition, CitiPower observes that the determination of the economies of scale adjustments by SKM was based on the approach previously used by ETSA and other DNSPs and TNSPs,[435] which has, in the main, been accepted by the AER.

In reviewing the economies of scale adjustments made by ETSA, the AER's expert, PB, concluded that:[436]

> *'the economy of scale adjustments that have been incorporated are reasonable and consistent with those used by similar businesses such as ElectraNet and Powerlink.'*

PB (and, in response, the AER) raised concerns only in respect of ETSA's economies of scale adjustment to emergency response opex.[437] For the reasons discussed below, CitiPower does not consider that the AER's conclusion in respect of ETSAs' escalation of emergency response opex can reasonably be applied to CitiPower's proposed escalation of emergency response opex.

CitiPower contests the changes made by the AER to the economies of scale adjustments to the following opex categories:

- emergency maintenance (function codes 309, 310, 312, 314, 315, 317 and 319);
- overhead line maintenance and pole defect maintenance (function codes 330 and 338); and
- salary expenditure (function code 635).

7.5.2.1 Emergency maintenance

In its Draft Determination, the AER increased CitiPower's proposed economies of scale adjustment to emergency maintenance opex from five per cent to 45 per cent to remove escalation of that portion of the forecast expenditure that it considered likely to relate to equipment failure (as opposed to external influences).[438]

The AER applied the reasoning that underpinned the South Australian Draft Determination, specifically, that *'emergency response not only includes responses to outages due to a variety of issues such as storms, animals contacting mains, etc but also from asset failures'*

[434] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

[435] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11; SKM, *R*eview of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p1.

[436] PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015, November 2009 (Attachment 135 to this Revised Regulatory Proposal), p138.

[437] PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015, November 2009 (Attachment 135 to this Revised Regulatory Proposal), pp138-9; AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), pp213-5; AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p115. PB also raised concerns in respect of ETSA's escalation of network access, monitoring and control opex activity. However, rather than raising concerns in respect of the economies of scale adjustment, PB indicated that the escalator applied by ETSA was not reasonable. The escalator applied by ETSA was a multi-factor escalator (based on ETSAs' network growth and worth volume escalators), whereas PB considered the costs of providing network access, monitoring and control are more closely aligned with full time employees directly employed in the activity than either network growth or work volume: PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015, November 2009 (Attachment 135 to this Revised Regulatory Proposal), pp140-2.

[438] AER, Draft Determination Appendices, Appendix J, pp101-2. The AER increased the economies of scale adjustment from five per cent to 45 per cent on the basis that (according to the AER's Victorian Electricity Businesses Comparative Performance Report 2008) the Victorian DNSPs' equipment failure and vegetation accounted for 45 per cent of supply interruptions: AER, Draft Determination Appendices, Appendix J, pp100-1.

and that, as asset replacement capex and preventative and corrective maintenance should directly reduce the level of emergency response opex because new or refurbished and maintained assets are less likely to fail, emergency maintenance expenditure arising due to asset failure should not be escalated.[439]

However, while the AER's position was upheld in the South Australian Final Determination, its reasons for that position were not.

In responding to the South Australian Draft Determination, ETSA highlighted that its escalation of emergency response opex involves taking the defect ratio that applies to its network today, and applying this same ratio to an enlarged network in the future.[440] ETSA noted that the average age of its assets will either remain stable or increase throughout the 2010-15 regulatory control period, and in the absence of a replacement capex program will progressively increase.[441] Thus, ETSA considered that there was no basis for an increase in the economies of scale adjustment applied to its emergency response opex.[442]

Accordingly, the AER did not reject ETSA's scale escalation of emergency response opex on the basis of the above. Rather, the AER rejected ETSA's proposed escalation because ETSA's modelling had taken asset age into account.[443] ETSA had proposed an asset age escalator, which it applied to 43 per cent of its emergency response opex (being the emergency response opex arising due to equipment failure rather than exogenous events).[444] As PB noted, '*it is through this mechanism ETSA Utilities has endeavoured to establish the relationship between asset age, defects and associated opex'*.[445]

PB recognised that the increasing weighted average age of key asset classes represented a risk to ETSA and recommended the application of age escalation.[446] While the AER rejected the proposed scale escalation of that proportion of ETSA's emergency response opex that related to asset failure,[447] the AER did so on the basis that it allowed asset age escalation of that opex.[448] That is, the AER implicitly recognised that it would not be appropriate to increase the economies of scale adjustment to emergency maintenance opex in the manner it proposed in its South Australia Draft Determination, in circumstances where the average age of network assets is increasing, unless the AER allowed age escalation of that opex.

[439] AER, Draft Determination Appendices, pp100-1; AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p214.
[440] ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), p120.
[441] ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), p120.
[442] ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), p120.
[443] AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p115.
[444] ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), pp124-7.
[445] PB, Review of ETSA Utilities' revised regulatory proposal for the period July 2010 to June 2015, May 2010 (Attachment 136 to this Revised Regulatory Proposal), p28.
[446] PB, Review of ETSA Utilities' revised regulatory proposal for the period July 2010 to June 2015, May 2010 (Attachment 136 to this Revised Regulatory Proposal), p35.
[447] AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p115.
[448] PB, Review of ETSA Utilities' revised regulatory proposal for the period July 2010 to June 2015, May 2010 (Attachment 136 to this Revised Regulatory Proposal), pp31-3; AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), pp119-20.

Subsequent to the Draft Determination, CitiPower engaged SKM to consider the average asset age of its network.[449] SKM's analysis suggests that, like ETSA, CitiPower's average network asset age, and the proportion of assets older than their nominal life, is expected to increase in the next regulatory control period.[450] Accordingly, CitiPower expects its emergency response opex will increase with growth in the network. In contrast to ETSA, CitiPower has not proposed an escalator for asset age. The AER cannot, therefore, reject CitiPower's scale escalation of emergency response opex on the basis that CitiPower has already sought to account for its increasing average network asset age through an age escalator.

CitiPower notes that new assets such as distribution transformers and zone substation primary and secondary equipment typically exhibit the classic 'bathtub' failure profile, where early in their life they exhibit failure rates (and require emergency maintenance) higher than in mid life. Therefore, as the network grows, the additional distribution transformers and zone substations implies additional emergency maintenance expenditure will be incurred. CitiPower observes that the fact that new assets may be repaired under warranty does not mitigate the need for scale escalation of emergency maintenance opex. This is because:

- the expenditure incurred under the emergency maintenance function codes (309, 310, 312, 314, 315, 317 and 319) largely relates to labour, and thus would not be covered by any supplier warranty;[451]
- for smaller distribution items (such as hardware associated with poles and wires), it is not economic for CitiPower to seek to claim on every warranty; and
- warranty periods generally only extend 12 months, after which time asset failures can, and do, occur,[452] and these failures are not covered by supplier warranties.

7.5.2.2 Overhead line maintenance and pole defect maintenance

The AER applied the same reasoning in respect of overhead line maintenance and pole defect maintenance as it did in respect of emergency maintenance opex.[453] The AER reasoned that as overhead line maintenance and pole defect maintenance is driven by defects, this implies that a greater proportion of activity is driven by asset failures (i.e. a greater proportion than the 45 per cent driven by asset failures for emergency maintenance opex).[454] Accordingly, the AER increased the economies of scale adjustment applied to function codes 330 and 338 from 5 per cent to 75 per cent.[455]

However, a significant volume of the work for overhead line maintenance and pole defect maintenance relates to routine asset inspection programs rather than asset failures. The programs involve preventive works to deal with 'defects' on the asset that, if not addressed, will cause the asset to fail in future. As CitiPower's network grows, more poles,

[449] SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal).
[450] SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p4.
[451] CitiPower notes that distribution network equipment has a long expected asset life and thus the assets are of a capital nature. Costs associated with asset replacement following asset failure are thus captured against capex function codes, rather than opex function codes.
[452] See, for example, SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p9. SKM's analysis shows instances of pole defects occurring, and transformer breakdown maintenance costs being incurred, throughout the assets lives.
[453] AER, Draft Determination Appendices, Appendix J, p101.
[454] AER, Draft Determination Appendices, Appendix J, p101.
[455] AER, Draft Determination Appendices, Appendix J, p101.

distribution transformers and zone substation equipment enter the maintenance system. As a consequence, more asset inspections and routine testing is scheduled. CitiPower submits that its proposed escalation of these function codes is appropriate.

Further, for the same reasons as outlined above in respect of the AER's rejection of scale escalation of emergency maintenance opex relating to asset failure, the AER's reasoning in the South Australian Draft Determination regarding ETSA's emergency maintenance opex cannot reasonably be used by the AER as a basis for rejecting scale escalation of overhead line maintenance and defect maintenance opex.

7.5.2.3 Salary expenditure

The AER was not satisfied that the salary expenditure function code represents increases in activity and not increases resulting from real wage inflation (or a combination of both).[456] The AER also considered that salary expenditure under this code is not linked to a specific function, which indicates that it is less likely to be driven by increases in activity levels.[457]

In its Draft Determination, the AER stated that the economies of scale adjustment for the salary expenditure function code was increased from 5 per cent to 100 per cent. However, CitiPower observes that the AER's scale escalation model adjusted the economies of scale factor for salary expenditure from 5 per cent to 75 per cent.[458]

The salary expenditure function code is applied only to salaries earned by CitiPower employees in the network business unit of CitiPower who do not time confirm (i.e. employees who do not allocate their time by project) and who undertake the following activities:[459]

- control and operations;
- inspection and maintenance;
- safety and environmental compliance;
- asset strategy and performance;
- customer projects; and
- engineering.

It is reasonable to expect that as the network grows, the activity for the above functions will also increase as there are more assets to plan, manage and maintain. That is, it is reasonable to assume that an increase in the number of assets will result in an increase in the level of activity by these network business unit employees.

7.5.3 Application of scale escalators and economies of scale adjustments

While not addressed in the AER's Draft Determination, CitiPower observes that the AER has applied scale escalation independently of input escalation.[460] This approach will lead to an error as the compounding effect of input cost and scale escalation has been ignored.

456 AER, Draft Determination Appendices, Appendix J, pp101-2.
457 AER, Draft Determination Appendices, Appendix J, pp101-2.
458 AER, Draft Determination Appendices, Appendix J, pp101-2; AER, spreadsheet titled 'CP_PAL_Scale_Opex_Economies of Scale_Draft_Decision' (provided to CitiPower by the AER by email on 24 June 2010).
459 Salaries of employees that are time confirmed (i.e. salaries of employees that allocate their time by project) are allocated directly to the relevant function code.
460 AER, spreadsheet titled 'CP PC_AER_Scale_Opex_Draft_Decision' (provided to CitiPower by the AER by email on 7 June 2010).

SKM agreed with CitiPower's proposed approach of applying scale escalators to input cost escalated opex because cost equals quantity by price and thus '*if both price (input cost escalator) and quantity (scale escalator) go up, the impact will be geometric, not a simple addition.*'[461]

Further, the AER calculated the economies of scale adjustments using the network growth, work volume and customer growth escalators included in CitiPower's Initial Regulatory Proposal, rather than its own escalators applied in the Draft Determination.[462] This introduces inconsistency into the Draft Determination and resulted in the scale escalation allowance in the Draft Determination being lower than it would otherwise have been.[463] CitiPower submits that it is imperative that, in its Final Determination, the AER uses the escalators it intends to apply when calculating the economies of scale adjustments.

7.5.4 Capex/opex trade-off

In its Draft Determination, the AER considered that because it had allowed reliability and quality maintained capex in the next regulatory control period above the historical level, this should result in a reduction in the level of required opex.[464]

CitiPower submits that the AER should not make a downward adjustment to its opex due to the reliability and quality maintained capex proposed in its Revised Regulatory Proposal. As noted above, SKM's analysis suggests that CitiPower's average network asset age, and the proportion of assets older than their regulatory life, is expected to increase in the next regulatory control period.[465] This implies that, when proper consideration is given to the characteristics of CitiPower's network, CitiPower's opex should be expected to **increase** (rather than decrease) in the next regulatory control period.

SKM has developed a rigorous, sophisticated capex/opex trade-off model that calculates the age of the network over a regulatory period at a detailed 'asset level'.[466] The model also calculates opex costs as a function of age calibrated against actual data.[467] The modelling conducted by SKM for CitiPower is the same as was conducted for ETSA in its recent price review process.[468] The analysis was accepted by PB (and therefore the AER in the South Australian Final Determination) on the basis that the SKM modelling was '*preferred and*

[461] SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), pp1, 13.
[462] AER, spreadsheet titled 'CP_PAL_Scale_Opex_Economies of Scale_Draft_Decision' (provided to CitiPower by the AER by email on 24 June 2010).
[463] This is because CitiPower's proposed escalators would have resulted in a larger (gross) increase in opex than the escalators applied in the Draft Determination. Using CitiPower's proposed escalators to determine the economies of scale adjustments therefore results in a larger reduction to the increase in opex than would otherwise have occurred, with the result that the increase in opex (net of the economies of scale adjustments) is smaller than would otherwise have been the case.
[464] AER, Draft Determination Appendices, Appendix J, pp106-8.
[465] SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p4.
[466] SKM's methodology is discussed in its reports attached to this Revised Regulatory Proposal: SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p15; SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), pp8-15.
[467] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p15; SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), pp8-15.
[468] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p15.

more accurate' compared with the approach originally substituted by PB.[469] The AER should therefore accept that SKM's analysis is more robust than the approach adopted by the AER in its Draft Determination.

In its Draft Determination, the AER determined the reduction in opex resulting from the increase in reliability and quality maintained capex in accordance with the approach outlined by PB prior to the South Australian Draft Determination.[470] The methodology:[471]

> *'involves calculating the annual ratio of compounding recommended asset replacement expenditure to the current (undepreciated) replacement cost of the asset base, and then applying 20% of this ratio to calculate the recommended adjustment in the network maintenance forecast opex.'*

CitiPower considers that the approach adopted by the AER to determining the capex/opex trade-off will not result in opex that reasonably reflects the opex criteria. This is because:

- the AER has made errors in its calculations;
- the methodology used by the AER is not likely to produce estimates of opex; and
- only around 18 per cent of CitiPower's opex was strongly linked to age and condition.[472]

CitiPower observes that the AER calculated the reduction to CitiPower's opex on the basis of the gross customer connections and reliability and quality maintained capex forecasts included in CitiPower's Initial Regulatory Proposal, rather than the capex forecasts substituted by the AER in its Draft Determination. Given the significant downward adjustment to CitiPower's proposed capex made in the AER's Draft Determination, the AER's calculation of the capex/opex trade-off amount is significantly overstated.

As noted by ETSA in response to the AER's South Australian Draft Determination,[473] the fundamental premise underlying PB's methodology is that, if the growth rate of asset replacement expenditure exceeds the rate at which a DNSP's network grows, a larger proportion of that network must be new and thus opex will decrease. However, such analysis fails to take into account the overall average age of the network. As noted by SKM, this approach considers only half of the ageing equation.[474] That is, the approach adopted by the AER takes into account the component that reduces asset age (i.e. replacement or reliability and quality maintained capex) but ignores the inevitable ageing of the asset base as a whole.[475]

SKM also considered that the AER's use of simplistic financial ratios was not adequate to analyse an issue as complex as the opex relationship to ageing network assets (including the

[469] PB, Review of ETSA Utilities' revised regulatory proposal for the period July 2010 to June 2015, May 2010 (Attachment 136 to this Revised Regulatory Proposal), p38.
[470] AER, Draft Determination Appendices, Appendix J, p107.
[471] PB, Review of ETSA Utilities' revised regulatory proposal for the period July 2010 to June 2015, November 2009 (Attachment 136 to this Revised Regulatory Proposal), p144.
[472] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p13.
[473] ETSA Utilities, Revised Regulatory Proposal 2010-2015, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), pp121-3.
[474] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p13.
[475] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p13.

effect of asset replacements) and thus failed to produce a result that is consistent with the opex costs faced by a prudent and efficient operator.[476]

CitiPower rejects the 20 per cent factor applied by PB and adopted by the AER.[477] Neither PB nor the AER has provided evidence to support the appropriateness of the factor.[478] PB observed in a footnote in its report supporting the South Australian Draft Determination:[479]

> *'accounts for reduced defect requirements with replace assets, and effectively reflects the proportion of total maintenance that is typically experienced by network owners associated with rectifying defects compared with the amount associated with routine inspections and maintenance. This proportion has been identified as typical, based in PB's experience working with a number of network owners across Australia.'*

CitiPower submits that this is a gross generalisation. Further, in its report on the AER's Draft Determination, SKM stated that it considered an appropriate adjustment would generally be well below 20 per cent for even the oldest assets.[480] CitiPower therefore submits that the 20 per cent adjustment made by the AER will not produce a reasonable estimate of the reduction in required opex CitiPower should expect in the next regulatory control period due to its increase in capex.

Finally, SKM noted that not all opex is likely to be affected by age.[481] Overall, SKM found that only around 18 per cent of CitiPower's opex was strongly linked to age and condition.[482] This significantly reduces the potential for replacement capex to reduce CitiPower's required opex.

In light of the above, the AER's adjustment for the capex/opex trade-off set out in the AER's Draft Determination cannot be considered reasonable and results in a significant understatement of the opex that CitiPower, acting efficiently and prudently, will require in the next regulatory control period. Acting conservatively, CitiPower has not included any amounts in this Revised Regulatory Proposal to reflect the increase in opex it anticipates will arise in the next regulatory control period given its proposed level of capex.

7.6 CitiPower's Revised Regulatory Proposal

For the reasons outlined above, in this Revised Regulatory Proposal, CitiPower has used the scale escalators set out in Table 7.5 below. The application of these escalators and the economies of scale adjustments made to each opex item are as set out in the Initial Regulatory Proposal, except as oulined in sections 7.5.1 and 7.5.2 above and as reflected in CitiPower's Cost Escalation Model.[483]

The resultant opex proposed by CitiPower as a result of this proposed scale escalation is set out in the following Table 7.6.

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[476] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p12.
[477] AER, Draft Determination Appendices, Appendix J, p107.
[478] This criticism is echoed by SKM: SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p14.
[479] PB, Review of ETSA Utilities' revised regulatory proposal for the period July 2010 to June 2015, November 2009 (Attachment 136 to this Revised Regulatory Proposal), p144, footnote 370.
[480] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p14.
[481] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p13.
[482] SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p13.
[483] Attachment 9 to this Revised Regulatory Proposal.

	Cumulative %				
	2011	2012	2013	2014	2015
Network growth	4.95%	7.38%	10.61%	13.68%	2.42%
Customer growth[484]	4.21%	5.65%	6.91%	8.83%	2.30%

Table 7.5 Scale escalators applied in CitiPower's Revised Regulatory Proposal

	2011	2012	2013	2014	2015	Total
Total scale escalation ($'000 2010)	407	843	1,265	1,817	2,401	**6,733**

Table 7.6 Opex resulting from CitiPower's proposed scale escalation

[484] See Revised Regulatory Template 6.1 in Attachment 1 to this Revised Regulatory Proposal.

8. REAL COST ESCALATORS

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to section 7.5.6 of, and Appendix K to, the AER's Draft Determination regarding CitiPower's input (or real) cost escalation and scale escalation. Specifically, this Chapter deals with CitiPower's:

- labour costs escalators used in developing its capex and opex forecasts; and
- materials escalators used in developing its capex and opex forecasts.

8.1 Summary of key points

In its Draft Determination, the AER substituted alternative escalators for the labour, contract and other costs and materials escalators (collectively, **input costs escalators**), as well as the scale escalators, proposed by CitiPower in its Initial Regulatory Proposal.

CitiPower does not accept the AER's forecasts of labour costs. In particular, CitiPower maintains that labour cost escalators based on the EGW measure will produce opex and capex forecasts that reflect a realistic expectation of cost inputs in the next regulatory control period.

In the Revised Regulatory Proposal, CitiPower uses labour cost forecasts prepared by KPMG which are based on AWE measures of wage growth and take account of projected productivity increases. Contrary to the approach taken by the AER to determining labour escalators for internal labour, CitiPower maintains that it is appropriate to apply the labour rate forecasts for the EGW industry to both specialist EGW employees and clerical and administrative staff.

In addition, CitiPower does not accept the AER's decision on its proposed materials escalators and, accordingly, provides updated materials escalators determined by independent engineering consultant, SKM, in this Revised Regulatory Proposal.

To address the AER's concerns regarding the currency of labour cost forecasts, CitiPower will update its labour cost forecasts closer to the date of the AER's Final Determination, at a date of the AER's choosing or, if no date is nominated by the AER, then CitiPower will provide the updated forecasts to the AER by 13 September 2010. Similarly, to address any currency concerns the AER may have regarding materials cost forecasts, CitiPower proposes to also provide the AER with updated materials cost forecasts.

8.2 Rule requirements

CitiPower applies input cost escalators in preparing the capex and opex forecasts for the 2011-15 regulatory control period and scale escalators to the input cost escalated opex forecasts. Accordingly, the provisions of the Rules governing capex and opex (detailed in Chapters 7 and 8 of this Revised Regulatory Proposal) apply. Broadly, the total capex and opex forecasts must reasonably reflect the capex and opex criteria respectively.

Of particular relevance for the purposes of the AER's assessment of the input cost escalators proposed by CitiPower is that the AER must accept the total capex and opex forecasts if they reasonably reflect (among other things) a realistic expectation of the cost inputs required to achieve the capex and opex objectives (clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the

Rules). If the AER is satisfied as to this (and the other opex and capex criteria), the AER must accept the total capex and opex forecasts without making any adjustments to them.

8.3 Labour and contract and other costs escalators

8.3.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower adopted labour escalators (for internal labour costs) and contract and other costs escalators (for outsourced labour costs) as determined by the independent economic consultant, BIS Shrapnel.[485]

In determining these escalators, BIS Shrapnel used the AWOTE measure as it considered this measure best reflects the increase in wage cost changes for business and the public sector across the economy.[486] BIS Shrapnel recommended that CitiPower use forecast changes to AWOTE in the EGW to escalate its internal labour costs[487] and a simple average of forecast changes to 'construction' and 'property and business services' wages to escalate its outsourced labour costs.[488]

The real labour cost growth and growth in contracts and other costs reflected in CitiPower's Initial Regulatory Proposal are set out in Table 8.1.

	% (real)					
	2010	2011	2012	2013	2014	2015
Labour cost growth	3.20	2.49	2.49	2.64	2.64	2.49
Growth in contracts and other costs	3.64	1.86	2.25	2.79	2.74	2.40

Table 8.1 Forecast labour cost growth and growth in contracts and other costs

8.3.2 AER's Draft Determination

8.3.2.1 Labour cost escalators (for internal labour)

While the AER indicated that BIS Shrapnel's methodology for determining labour cost escalators appeared reasonable, the AER raised some concerns with BIS Shrapnel's approach. In particular, the AER raised concerns with:[489]

- BIS Shrapnel's use of AWOTE (rather than LPI) to measure labour cost growth; and
- the application of an EGW based escalator to 100 per cent of CitiPower's internal labour costs.

The AER also indicated in its Draft Determination that:[490]

- it considered compensating a DNSP for actual EBA wage increases largely eliminates the incentive for a DNSP to actively pursue efficient and competitive wage outcomes during EBA negotiations;

[485] BIS Shrapnel's methodology and findings are set out in the report Wages Outlook for the Electricity Distribution Sector in Victoria, August 2009, (Attachment C0040 to the Initial Regulatory Proposal).
[486] BIS Shrapnel, Wages Outlook for the Electricity Distribution Sector in Victoria, Final Report, August 2009(Attachment C0040 to the Initial Regulatory Proposal), p10.
[487] CitiPower notes that it treated the labour costs incurred by CHED Services and PNS as 'internal' labour costs for the purposes of labour cost escalation.
[488] BIS Shrapnel, Wages Outlook for the Electricity Distribution Sector in Victoria, Final Report, August 2009, (Attachment C0040 to the Initial Regulatory Proposal), p1.
[489] AER, Draft Determination Appendix K, pp132-7.
[490] AER, Draft Determination Appendix K, pp132-7.

- productivity impacts in modelling labour escalators can be an important factor in forecasting actual business costs; and
- the DNSPs' forecasts should be updated to reflect the most recent data.

For these reasons, the AER:[491]

- substituted labour cost growth forecasts determined by its consultant, Access Economics; and
- limited the application of Access Economics' EGW measure to 78 per cent of CitiPower's internal labour costs (a percentage it determined based on data in the Revised Regulatory Templates).

8.3.2.2 Contract and other costs escalators (for outsourced labour)

The AER rejected the contract and other cost escalators put forward by BIS Shrapnel on the basis that the data used to develop the forecast was not the most recent available.[492] While it did not explicitly indicate as much in respect of the contract and other costs escalators, presumably the AER also rejected the BIS Shrapnel escalators for outsourced labour on the basis that:

- BIS Shrapnel used AWOTE (rather than LPI) to measure labour cost growth; and
- the productivity impacts in modelling labour escalators were not taken into account.

The AER substituted an 'outsourced' labour cost escalator determined by Access Economics.[493]

8.3.3 CitiPower's response to the Draft Determination

CitiPower expects that there will be a significant upward pressure on the wages of skilled employees in the EGW sector over the next regulatory control period.

The continued wage growth in this sector reflects persistent strong demand for labour, as a result of large and growing construction programs and expansion services. It also reflects the nature of labour in these essential services industries, with a high proportion of skilled workers and the need for uninterrupted service. While higher wages are expected to attract new workers to the electricity sector, skills imbalances take some time to resolve, as entry into electricity distribution field work, for example, requires a four year apprenticeship to be undertaken, and a further two years of on-job training and experience.

Specific to the Victorian electricity distribution sector there are a number of unique investment requirements that will increase the demand for labour resources. These are:

- a number of Victorian DNSPs, such as CitiPower, will have a significant number of assets reaching the end of their economic life over the next regulatory control period. This will trigger significant capex on asset replacements; and
- the mandated accelerated roll out of interval meters which has already commenced will require the replacement of over 2,000,000 meters across Victoria.

Increased demand for labour will not only be driven by demand in Victoria, but by demand across Australia:

[491] AER, Draft Determination Appendix K, pp132-7.
[492] AER, Draft Determination Appendix K, pp136-7.
[493] AER, Draft Determination Appendix K, p139.

- capex in NSW is forecast for the next five years in the order of $14.4 billion ($2008-09) based on the AER's NSW Final Determination; and
- opex in Queensland is forecast for the next five years in the order of $10.8 billion ($2009-10) based on the AER's Queensland Final Determination.

Taken together, these substantial increases on expenditure will lead to significant increases in demand for skilled labour in an already tight national market.

8.3.3.1 Labour cost forecasting methodology

As noted above, the AER raised two main methodological issues with CitiPower's proposed labour cost and contract and other cost escalators:

- the labour cost forecasts were based on an AWE measure rather than an LPI measure; and
- the labour cost forecasts did not reflect projected increases in productivity.

The AER also sought to raise as an issue the currency of the data underlying CitiPower's labour cost escalators. Each of these issues is discussed in turn below.

AWE versus LPI

The ABS publishes several labour cost indicators. The indicators of relevance in this price review are the AWE and LPI measures.

The AWE is based on a quarterly sample survey of approximately 5,500 employers.[494] It measures the average weekly earnings of employed wage and salary earners (excluding those employed in private agriculture).[495] The estimates of the AWE are calculated by dividing estimates of weekly total earnings by estimates of the number of employees.[496]

The AWE provides three earnings measures:

- AWOTE;
- AWTE; and
- average weekly total earnings (i.e. including overtime) of full-time employees.

The LPI is based on a survey sample of approximately 4,800 employers.[497] Employers provide hourly wage and salary costs for a sample of jobs in their workforce.[498] In subsequent quarters, employers provide details of payments made to the current occupants of these same jobs.[499]

In its Draft Determination, the AER agreed with its consultant, Access Economics, that the LPI is the measure that most reasonably reflects the labour costs for DNSPs in Victoria.[500]

[494] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 3 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p22.
[495] ABS, 6301.0 Average Weekly Earnings, February 2010 available at www.abs.gov.au, accessed 8 July 2010 (Attachment 151 to this Revised Regulatory Proposal).
[496] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 3 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p23.
[497] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p23.
[498] ABS, 6345.0 Labour Price Index, March 2010 available at www.abs.gov.au, accessed 17 July 2010 (Attachment 144 to this Revised Regulatory Proposal).
[499] KPMG, Labour Cost Forecasts for Powercor and CitiPower (Attachment 143 to this Revised Regulatory Proposal), 13 July 2010, p24.
[500] AER, Draft Determination Appendix K, p132.

Access Economics concluded that LPI was the preferred measure on the basis that the ABS sees LPI as its preferred measure for 'changes in the price of labour' and as it is not affected by shifts in the composition of employment.[501]

The AER's decision to accept the LPI measure in its Draft Determination is contrary to its Jemena Gas Access Final Decision where the AER approved BIS Shrapnel's AWOTE forecasts, its SP AusNet Final Transmission Determination where it approved BIS Schrapnel's AWOTE forecasts and its NSW Final Determination where it accepted KPMG's AWE forecast.

The AER when determining the most appropriate wage measure to adopt for the purposes of forecasting the businesses' labour cost should consider 'fitness of purpose'. While the AER notes that ABS has stated that the LPI is a preferable measure over AWE/AWOTE, the ABS developed the LPI in response to the decentralisation of the labour market and more employees being covered by diverse agreements. The LPI purposely ignores these agreements to capture the 'underlying wage trend' and provide a 'high-level' index for the economy. The LPI was not developed for the purposes of forecasting actual labour costs for a business.

It is relevant for the purposes of escalating labour costs that the composition of the workforce is changing. Rather than viewing the fact that the LPI does not take compositional changes into account as a reason for adopting the measure, BIS Shrapnel noted the following:[502]

> *'Importantly, the LPI does not reflect changes in the skill levels of employees within industries or for the overall workforce, and will therefore understate (or overstate) wage inflation if the overall skill levels increase (or decrease). The labour price index is also likely to understate true wage inflationary pressures as it does not capture situations where promotions are given in order to achieve a higher salary for a given individual, often to retain them in a tight labour market… [P]romoting employees to a higher occupation category would not necessarily show up in the labour price index. However, the employer's total wages bill (and unit labour costs) would be higher.'*

While Access Economics recognised that it is sometimes relevant that the composition of the workforce is changing, particularly during sustained expansion, Access Economics considered that the LPI's downward bias is unlikely to have been large given it has existed only since 1997 and Australia's economic expansion began in 1992.[503] In addition, Access Economics considered that the slow down in the economy means that the pace of promotions is slowing and thus, other things being equal, the LPI is more likely to overstate potential wage growth than understate it.[504]

As the Australian economy's expansion continued following the commencement of the LPI in 1997, so too did the compositional shift. This means that the commencement of the expansion period in 1992 and the commencement of the LPI measure in 1997 does not address the concerns with downward bias (acknowledged by Access Economics) associated with the LPI.

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501 Access Economics, Forecast growth in labour costs: March 2010 report, 16 March 2010, pp112-3.

502 BIS Shrapnel, *Wages Outlook for the Electricity Distribution Sector in Victoria, Final Report*, August 2009, included as Attachment C0040 to the Initial Regulatory Proposal, p10.

503 Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, pp113-4.

504 Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, p114.

This view on the slow down in the economy and the resultant conclusion that the LPI is more likely to overstate than understate potential wage growth is inconsistent with Access Economics' views expressed elsewhere in the report. For example, Access Economics noted:[505]

> *'Global economic recovery is underway, and Australia's recovery is outpacing it, suggesting that 2010 will see improving rates of economic growth, and hence also some unwinding of the emergency policy supports put in place through the period of crisis.'*

Access Economics' position also contrasts with the views of KPMG. In its Labour Cost Forecasts report, KPMG discusses the different labour cost indicators published by the ABS: the AWE, the LPI, the mean weekly earnings and compensation of employees measures.[506]

KPMG concludes that the AWE is the more appropriate measure based on its statistical reliability and conceptual suitability.

In respect of its statistical reliability, KPMG finds that the AWE (at the state by industry level) is the best source to measure wage movements because it:[507]

- is available for a longer historical period than the LPI, meaning it is more amenable to robust statistical analysis; and
- is less volatile than the mean weekly earnings and compensation of employees figures.

At a conceptual level, KPMG finds that the AWE is more suitable than the LPI as compositional impacts are taken into account (i.e. the impacts of the composition of the employee workforce).[508] KPMG indicates that compositional impacts are expected to continue to play an influential role in the overall labour costs faced by employers over the forecast period.[509] This is because, during the recent economic downturn there were changes to the composition of the workforce, which are expected to be reversed out as the economy recovers. For example, while there was a move to put promotions on hold during the downturn, as the labour market tightened, promotions are expected to resume in the forthcoming regulatory control period as firms seek to retain individuals. In addition, over the longer term, population ageing will influence the composition of employment as more experienced workers retire and are not replaced.[510]

While both KPMG and BIS Shrapnel use AWE measures, KPMG uses the AWTE and BIS Shrapnel utilises the AWOTE. The difference between the measures is that the AWTE takes into account part-time employees and overtime, while the AWOTE does not. As KPMG observes, the movements within the AWOTE and AWTE have generally been quite similar.[511] KPMG observes that:[512]

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[505] Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, p11.

[506] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010, (Attachment 143 to this Revised Regulatory Proposal), p22-27.

[507] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p28.

[508] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), pp28-30.

[509] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p30.

[510] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p30.

[511] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p30.

'if the compositional shares between full-time and part-time workers, and the ratio of ordinary time to overtime worked are expected to be fixed, AWOTE can be considered to be as good a measure as the AWE for the purposes of generating labour cost forecasts.'

Accordingly, CitiPower considers escalators based on an AWE measure (and not the LPI) will produce opex and capex forecasts that reflect a realistic expectation of cost inputs in the next regulatory control period.

Productivity

As noted above, the AER supported the application of productivity impacts in forecasting wage cost growth.[513]

CitiPower does not consider that labour cost forecasts used to escalate labour costs in DNSP price review processes should take productivity improvements into account because this distorts the incentives for efficiency that would otherwise be created by the AER's EBSS.

However, as discussed further below, the forecasts on which CitiPower's labour and contract and other costs escalators proposed in this Revised Regulatory Proposal are based do take into account productivity improvements. Accordingly, CitiPower's in principle position that productivity improvements should not be taken into account is not reflected in this Revised Regulatory Proposal, and the AER cannot reject CitiPower's proposed labour and contract and other costs escalators on the basis of failure to take into account productivity improvements.

Currency of data

Contrary to the AER's apparent reasoning in its Draft Determination,[514] currency of data is not a reason for rejecting a DNSP's proposed methodology for determining input cost escalators.

To address the AER's concerns regarding the currency of CitiPower's labour cost escalators, CitiPower is proposing to engage KPMG to provide updated labour cost forecasts closer to the date of the AER's Final Determination, at a date of the AER's choosing. If the AER does not advise of the date by which it would like the updated forecasts, CitiPower will provide the updated forecasts to the AER by 13 September 2010.

8.3.3.2 Labour costs escalators (for internal labour)

CitiPower submits that it is not reasonable to use the growth rates determined by Access Economics. Rather, CitiPower considers that EGW forecasts provided by KPMG constitute a 'realistic expectation' of labour costs in the 2011-15 period. Accordingly, in this Revised Regulatory Proposal, CitiPower's has used labour cost escalators based on KPMG's EGW forecasts. CitiPower considers that use of those labour cost escalators results in total capex and opex forecasts that reasonably reflect the capex criteria and opex criteria.

In addition, CitiPower submits that:

- contrary to the AER's position, it is appropriate to take into account CitiPower's EBA rates for 2010; and

[512] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p31.
[513] AER, Draft Determination Appendix K, p133.
[514] AER, Draft Determination Appendix K, pp136-7.

- contrary to the AER's position, it is reasonable to apply the growth in the EGW labour rate to 100 per cent of CitiPower's internal labour costs.

Each of these issues is expanded upon below.

Access Economics forecasts

In forecasting growth in internal labour costs for the next regulatory control period, it is not reasonable to use the growth rates determined by Access Economics. This is because:

- Access Economics uses the LPI rather than an AWE measure of wage growth;
- there are problems with the method Access Economics employs to generate its State by industry LPI data series; and
- the forecasts prepared by Access Economics are significantly lower than those developed by KPMG, which suggests that they do not constitute a 'realistic expectation' of cost inputs over the regulatory control period.

The reasons why escalators based on AWE measures are more likely than escalators based on the LPI to result in forecasts that reflect the cost inputs required to achieve the capex and opex objectives are set out above.

In addition to its criticism of the use of LPI as opposed to AWE in its report foreshadowed above[515], KPMG observes in its report, Assessment of the AER's Draft Decision on Labour Cost Escalation: Victoria, that there are issues related to data availability and the method employed by Access Economics to generate its State by industry LPI data series. [516] KPMG notes that the issues stem from the fact that LPI data is itself not fully available for all one-digit level industries in each State economy.

KPMG states that:

- in Access Economics' LPI model, when a sectoral LPI is not available for a given State, sectoral AWOTE data (as a deviation from the national/State AWOTE) is used to estimate the sectoral LPI;
- applying estimates from the AWOTE series to estimate State by industry LPI does not automatically ensure consistency between the different LPI services, rather additional adjustments would need to be made to the State by industry LPIs;
- a failure to ensure consistency can lead to a downward bias in wage forecasts as wage pressures that arise from sectoral competition are not adequately accounted for; and
- since Access Economics provides no information on how, or if, such adjustments have been made, it is not clear that its model ensures consistency between detailed State by industry series and the aggregated series at the State level and the national industry level.

Further, KPMG observes that Access Economics developed labour cost forecasts by linking movements in the LPI to a range of underlying economic drivers, including GDP. Access Economics' GDP forecasts prepared in March 2010 are outdated and overly pessimistic.[517]

[515] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010, (Attachment 143 to this Revised Regulatory Proposal),.

[516] KPMG, Assessment of the AER's Draft Decision on Labour Cost Escalation: Victoria, 13 July 2010 (Attachment 156 to this Revised Regulatory Proposal), p22-3.

[517] KPMG, Assessment of the AER's Draft Decision on Labour Cost Escalation: Victoria**,** 13 July 2010, (Attachment 156 to this Revised Regulatory Proposal), p34 and 39.

As a result, the associated wage forecasts prepared by Access Economics are likely to understate the wage pressures currently being created by labour demand in the economy. In addition, KPMG Economics notes that Access Economics' more recent short run GDP forecasts are pessimistic in comparison to those of the RBA and KPMG. This would suggest that Access Economics' forecasts are at the bottom of the range of reasonable expectations of future growth. As a result, Access Economics' LPI forecasts may underestimate wage pressures being created by growing labour demand.

The fact that the forecasts prepared by Access Economics are significantly lower than the forecasts developed by KPMG, suggests that they do not constitute a 'realistic expectation' of cost inputs in the 2011-15 period and would not lead to forecasts that reasonably reflect the capex criteria and opex criteria.

CitiPower's proposed labour costs escalators

For the purposes of preparing this Revised Regulatory Proposal, CitiPower engaged KPMG to forecast growth in labour costs for the next regulatory control period. CitiPower considers that KPMG's EGW forecasts constitute a 'realistic expectation' of labour costs in the 2011-15 period and, accordingly, that CitiPower's revised escalators, based on KPMG's EGW forecasts, produce total capex and opex forecasts that reasonably reflect the capex criteria and opex criteria.

Consistent with the discussion earlier in this Chapter, the AER should accept CitiPower's labour costs escalators because they:

- are based on AWE measures, rather than the LPI; and
- take into account anticipated increases in productivity.

CitiPower also notes that KPMG's forecasts were calculated using a model developed for the AER, which has been accepted by the AER in previous regulatory decisions.

KPMG's LCM was purpose built for the AER in 2007 for the purposes of the SP AusNet Final Transmission Determination.[518] Forecasts produced by LCM were relied on by the AER in decisions as set out in Table 8.2 below.

[518] Econtech, Labour cost growth forecasts 2007/08 to 2016/17, 19 September 2008 (Attachment 146 to this Revised Regulatory Proposal), p1; AER, NSW Draft Determination (Attachment 142 to this Revised Regulatory Proposal), p489, footnote 1311.

AER decision	Use of KPMG's LCM forecasts by AER
AER, SP AusNet Draft Transmission Determination	AER used Econtech's[519] forecasts to conclude that the forecasts provided by SP AusNet (prepared by BIS Shrapnel) were *'not excessive'*.[520] The AER concluded that, as there was not a significant difference between the forecasts prepared by the AER's two consultants, Econtech and PB, and those prepared by SP AusNet's consultant, BIS Shrapnel, the AER considered SP AusNet's forecast reasonably reflected a realistic expectation of labour cost increases.[521]
AER, SP AusNet Final Transmission Determination	AER used Econtech's forecasts to conclude that the forecasts put forward by SP AusNet (prepared by BIS Shrapnel) should be accepted. The AER noted that Econtech's analysis was *'sufficiently robust… to rely on … in assessing the reasonableness of SP AusNet's proposal.'* [522]
AER, NSW Draft Determination	The AER was satisfied that Econtech's forecasts were robust and applied these.[523]
AER, NSW Final Determination	The AER adopted updated Econtech forecasts.[524] The AER considered that Econtech's methodology was robust and transparent.[525]

Table 8.2 Development and use of KPMG's LCM model

While no longer relevant as it is proposing to apply escalators based on KPMG's labour growth forecasts, CitiPower notes that, contrary to the concerns expressed by the AER in the Draft Determination,[526] its escalators in the Initial Regulatory Proposal did not represent a moving average. Rather, CitiPower took a simple average of labour growth forecasts for two financial years to calculate the nominal escalator for a calendar year (e.g. CitiPower took the simple average of BIS Shrapnel's 2011-12 and 2012-13 financial year figures to calculate the nominal escalator for the 2012 calendar year).

Impact of collective bargaining

As noted above, the AER considered in its Draft Determination that compensating a DNSP for actual EBA wage increases in its expenditure forecasts largely eliminates the incentive for a regulated DNSP to actively pursue efficient and competitive wage outcomes during EBA negotiations. This assumption is incorrect.

[519] Econtech Pty Ltd merged with KPMG in August 2008: AER, NSW Draft Determination (Attachment 141 to this Revised Regulatory Proposal), p534, footnote 1238.
[520] AER, Draft Decision, SP AusNet Transmission Determination 2008-09 to 2013-14, 31 August 2007 (Attachment 147 to this Revised Regulatory Proposal), p141.
[521] AER, Final Decision, SP AusNet Transmission Determination 2008-09 to 2013-14, 14 January 2008 (Attachment 148 to this Revised Regulatory Proposal), pp114-115. The difference between the forecasts was average nominal annual growth of 6.38% in the case of Econtech, and 5.13% in the case of PB.
[522] AER, Final Decision, SP AusNet Transmission Determination 2008-09 to 2013-14, 14 January 2008 (Attachment 148 to this Revised Regulatory Proposal), p116.
[523] AER, NSW Draft Determination (Attachment 142 to this Revised Regulatory Proposal), p538.
[524] AER, NSW Final Determination (Attachment 141 to this Revised Regulatory Proposal), pp495-6.
[525] AER, NSW Final Determination (Attachment 141 to this Revised Regulatory Proposal), pp491-2.
[526] AER, Draft Determination, p127.

Victorian DNSPs will continue to have an incentive to strongly negotiate EBA rates in the next regulatory control period because of the incentives built into the regulatory regime, that is, the AER's EBSS. In adopting a revealed cost approach to forecasting capex and opex in the next regulatory control period, the AER has accepted that the ESCV's efficiency carry over mechanism ensured that DNSPs had incentives to incur only efficient capex and opex in the current regulatory period. The same efficiency incentives will be created in the 2011-15 period by the AER's EBSS.

The AER indicated in its Draft Determination that it would *'observe the actual EBA rate increases incurred by the Victorian DNSPs up until the beginning of the forthcoming regulatory control period.'*[527] However, the AER, as illustrated by the AER's conclusion on the internal labour real cost escalators, has not done so.

The AER should take into account its current EBA rates for 2010. Further, as noted above, CitiPower's current EBA rates were negotiated at a time when the ESCV's efficiency carry over mechanism provided incentives for CitiPower to incur only efficient opex, including labour costs. Finally, the AER has previously accepted that it is reasonable to adopt actual EBA wage increases in the current regulatory control period.[528]

Application of labour cost escalators

The AER rejected BIS Shrapnel's application of EGW rates to internal labour cost forecasts.[529] The AER indicated that the EGW did not reflect the underlying composition of the workforce and an alternative growth rate should be applied to those internal labour costs that relate to clerical and administrative staff.[530]

To determine the composition of the workforce, the AER used the Initial Regulatory Templates to derive a 'split' of labour costs associated with specialist EGW employees and labour costs associated with clerical and administrative staff.[531] The AER then applied these estimated weightings to the EGW and general Victorian wage growth forecasts prepared by Access Economics to determine a weighted average labour cost growth forecast.[532]

Implicit in the AER's Draft Determination is an assumption that EGW wage measures reflect only wages paid to specialist EGW employees and not wages paid to clerical and administrative staff working in the electricity, gas or water industries.[533] This assumption is incorrect.

The EGW measures are calculated based on the earnings of employees of businesses in the EGW industry, which means that it includes both EGW specialist occupations and other occupations. ABS has confirmed that its AWE and LPI statistics for the EGW industry reflect all employees in the EGW industry and not just specialist EGW employees.[534]

Accordingly, as noted by KPMG, if the composition of CitiPower's internal workforce (including employees seconded to CHED Services and PNS) is similar to the average for the

[527] AER, Draft Determination Appendix K, p136.
[528] AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p96.
[529] AER, Draft Determination Appendix K, pp133-4.
[530] AER, Draft Determination Appendix K, pp134-5.
[531] AER, Draft Determination Appendix K, p135.
[532] AER, Draft Determination Appendix K, p135.
[533] AER, Draft Determination Appendix K, p134.
[534] Email from ABS to DLA Phillips Fox regarding LPI, 8 July 2010 (Attachment 149 to this Revised Regulatory Proposal); Email from ABS to DLA Phillips Fox regarding AWE, 8 July 2010 (Attachment 150 to this Revised Regulatory Proposal); ABS 6302.0 Average Weekly Earnings, Australia, February 2010 (Attachment 151 to this Revised Regulatory Proposal).

industry, changes in internal labour costs would be adequately reflected in EGW measures.[535]

CitiPower therefore maintains that it is reasonable to apply the growth in the EGW labour rate to 100 per cent of its internal labour costs. In preparing this Revised Regulatory Proposal, CitiPower has applied the growth in EGW labour costs forecast by KPMG to all of its internal labour costs (including CHED Services and PNS labour).

8.3.3.3 Contract and other costs escalators (for outsourced labour)

Access Economics forecasts

Access Economics' forecasts for outsourced labour costs are not realistic estimates of the input costs likely to face CitiPower in the next regulatory control period. This is because Access Economics' forecasts are based on the LPI rather than an AWE measure, which, for the reasons outlined above, is not an appropriate measure of the increase in labour costs. Further, Access Economics' forecasts of growth in Victorian wages are considerably lower than the all industries forecasts prepared by KPMG as shown in the following graph.

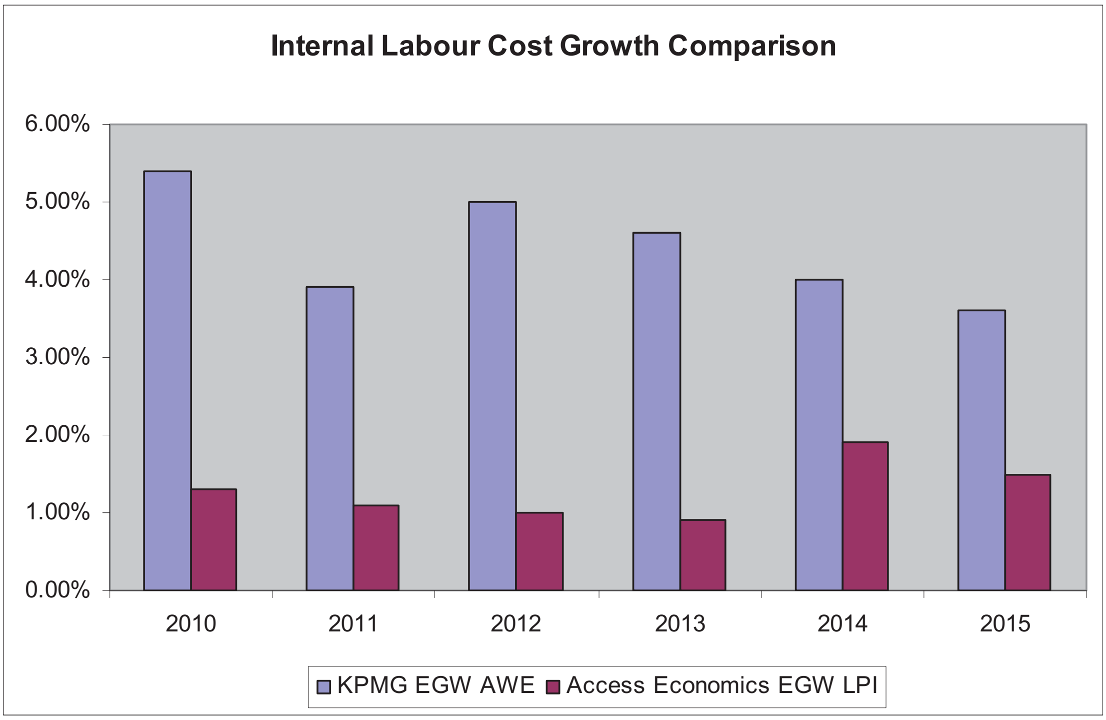

Figure 8.1 Graph comparing KPMG's labour cost forecast to Access Economics' labour cost forecast

CitiPower's proposed contract and other cost escalators

The contract and other costs escalators proposed by CitiPower in this Revised Regulatory Proposal are based on KPMG's forecasts. CitiPower considers these escalators reflect a realistic expectation of the external labour costs that will be incurred by CitiPower in the next regulatory control period.

As noted above, KPMG's forecasts are based on AWE measures of wage growth and take into account productivity impacts.

[535] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p33.

CitiPower has proposed in this Revised Regulatory Proposal contract and cost escalators equal to the simple average of the 'construction' and 'administrative support services' forecasts prepared by KPMG. In its Draft Determination, the AER accepted that it was reasonable to use a simple average of the Victorian 'construction' and 'property business services' measures to determine outsourced labour costs.[536] However, the 'property and business services' classification has since been split into three separate industry classifications:[537]

- rental, hiring and real estate services;
- professional, scientific and technical services; and
- administrative and support services.

Of these, KPMG recommended that the 'administrative and support services' category was the most appropriate to use together with the 'construction' category for the purposes of the outsourced labour costs.[538] In calculating its contract and other costs escalators, CitiPower has taken the simple average of each of the measures forecast by KPMG.

8.4 Materials escalators

8.4.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower adopted materials escalators as determined by independent engineering consultants SKM.[539]

8.4.2 AER's Draft Determination

The AER made a number of adjustments to the materials escalators proposed by CitiPower.[540]

8.4.3 CitiPower's response to the Draft Determination

Since its Initial Regulatory Proposal, in July 2010 SKM provided CitiPower with updated materials escalators which bring into account more recent market information that has become available since the development of the escalation rates used in its Initial Regulatory Proposal.[541]

In determining the updated the materials escalators SKM gave consideration to the AER's assessment of real cost escalators in its Draft Determination. SKM's report includes an evaluation of the AER's conclusions in relation to real cost escalation rates.[542]

In updating the materials escalators, SKM incorporated the following changes having regard to the AER's Draft Determination:[543]

[536] AER, Draft Determination Appendix K, p136.
[537] ABS, Australian and New Zealand Standard Industrial Classification (ANZSIC), 2006 (Attachment 152 to this Revised Regulatory Proposal), paragraph 1.37, p11. A description of the previous Property and Business Services Division is contained in ABS, 1292.0, Australian and New Zealand Standard Industrial Classification (ANZSIC), 1993 (Attachment 153 to this Revised Regulatory Proposal).
[538] KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p33.
[539] SKM's methodology and findings are set out in the report Victorian Distribution Network Service Providers annual material cost escalators 2010-15 (Attachment C0041 to the Initial Regulatory Proposal).
[540] AER, Draft Determination Appendix K, pp118-125, 139-145.
[541] SKM, Victorian Distribution Network Service Providers cost escalator updates, Final Report – CitiPower and Powercor Asset Categories, 8 July 2010 (Attachment 155 to this Revised Regulatory Proposal), p15.
[542] SKM, Victorian Distribution Network Service Providers cost escalator updates, Final Report – CitiPower and Powercor Asset Categories, 8 July 2010 (Attachment 155 to this Revised Regulatory Proposal), p3-13.

- SKM did not include a CPRS/Carbon component;
- SKM did not include any real escalation of wood poles; and
- SMK did not include a Trade Weighted index component.

CitiPower has used the updated materials escalators in SKM's July 2010 report for the purposes of preparing this Revised Regulatory Proposal. However, to address any concerns the AER may have regarding the currency of materials cost forecasts, CitiPower will update its materials cost forecasts closer to the date of the AER's Final Determination, at a date of the AER's choosing or, if no date is nominated by the AER, then CitiPower will provide the updated forecasts to the AER by 13 September 2010.

8.5 CitiPower's Revised Regulatory Proposal

For the reasons outlined above, in this Revised Regulatory Proposal, CitiPower has applied the escalators set out below.

	% (real)					
	2010	2011	2012	2013	2014	2015
Labour costs	6.85	3.54	4.61	3.93	3.05	2.86
Contracts and other costs	4.98	2.22	2.37	1.44	0.91	1.25

Table 8.3 Labour and other contract cost escalators reflected in CitiPower's Revised Regulatory Proposal

	% (real)					
	2010	2011	2012	2013	2014	2015
Network	9.14	6.08	-0.09	-0.36	-1.14	-1.16
SCADA/network control	1.96	0.18	0.42	-0.07	-0.07	-0.07
Non network general IT	1.96	0.18	0.42	-0.07	-0.07	-0.07
Non network general other	1.96	0.18	0.42	-0.07	-0.07	-0.07
Weighted average	8.73	5.73	-0.08	-0.35	-1.07	-1.09

Table 8.4 Materials cost escalators reflected in CitiPower's Revised Regulatory Proposal

[543] SKM, Victorian Distribution Network Service Providers cost escalator updates, Final Report – CitiPower and Powercor Asset Categories, 8 July 2010 (Attachment 155 to this Revised Regulatory Proposal), p14.

Table 8.5 below shows net capex due to labour cost escalation.

	$,000 ($2010)					
	2010	2011	2012	2013	2014	2015
Labour escalation	1,737	3,691	5,493	7,934	8,403	8,505
Material escalation	2,553	5,296	6,320	6,570	6,546	5,766
Contract & other cost escalation	2,801	5,592	8,045	10,157	10,703	11,117

Table 8.5 Net capex due to real cost escalation

Table 8.6 below shows opex due to labour cost escalation.

	$,000 ($2010)					
	2010	2011	2012	2013	2014	2015
Labour escalation	0	455	1,122	1,778	2,318	2,840
Material escalation	0	77	66	54	34	14
Contract & other cost escalation	0	489	990	1,237	1,271	1,532

Table 8.6 Opex due to real cost escalation

9. FORECAST CAPITAL EXPENDITURE

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 8 of the AER's Draft Determination regarding CitiPower's capex forecasts for standard control services for the next regulatory control period and Appendix N to the Draft Determination regarding equity raising costs.

9.1 Summary of key points

CitiPower does not accept the AER's rejection of its proposed capex forecasts for the next regulatory control period. CitiPower submits that the AER's downward adjustment of just over $490 million over the next regulatory control period results in a capex allowance that does not reasonably reflect the capex criteria and does not constitute the minimum adjustment to CitiPower's proposed capex allowance necessary for the resultant allowance to reasonably reflect the capex criteria.

9.1.1 General

There are several issues in the AER's Draft Determination that are relevant to the AER's assessment of CitiPower's proposal for a number of capex categories. Specifically, CitiPower is concerned with the following:

- the inconsistency of the AER's approach to the Draft Determination with previous AER distribution determinations and decision making processes;
- the imposition of new evidentiary threshold requirements that are impermissible at law, and which are unduly onerous and demanding and ignore the difficulties which will ordinarily confront a regulated business in a price review process;
- the AER's failure to use 2009 actual data provided to it to model historical expenditure;
- the AER's 'revealed cost' approach to producing substitute forecasts of capex for the next regulatory control period;
- the failure by the AER to make the minimum adjustment to CitiPower's forecast necessary to enable the AER to approve the capex under the Rules, as required by clause 6.12.3(f);
- the lack of practical and relevant experience in operating an Australian distribution network of the authors of the Nuttall Consulting report relied on by the AER for the purposes of its Draft Determination in respect of capex; and
- the AER's incorrect finding that CitiPower's historical forecasting accuracy is poor.

9.1.2 New customer connections capex

CitiPower has amended its customer connections capex forecasts in this Revised Regulatory Proposal to:

- respond to the AER's concerns with its calculation of gross customer connections capex; and

- reflect the AER's recent decision regarding CitiPower's upstream augmentation charge rates.[544]

However, CitiPower contends that the AER has made an error in removing function codes 114 and 115 from standard control and allocating them to alternative control.

CitiPower does not accept the AER's rejection of all proposed expenditure under function code 118. CitiPower expects to receive a number of requests for embedded generation connection in the next regulatory control period and, accordingly, has included an amount against this function code to allow for this.

9.1.3 Reinforcement capex

CitiPower submits that its methodology for forecasting reinforcement capex does not result in a systematic upward bias in the estimate of future prudent and efficient reinforcement capex. This is because:

- CitiPower's internal planning criteria incorporate the same criteria as CitiPower's governance documents, which Nuttall Consulting concluded would be expected to deliver prudent and efficient outcomes;
- CitiPower's processes take into account synergies and result in forecasts that are economically justified;
- overall, SKM found that CitiPower's energy at risk modelling (including its load duration and transformer outage rate assumptions) is likely to **understate** energy at risk; and
- the zone substation level maximum demand forecasts used to prepare the reinforcement capex forecasts are consistent with NIEIR's system maximum demand forecast and thus the maximum demand forecasts used to forecast reinforcement capex are not likely to result in a systematic upward bias in the estimate.

CitiPower rejects Nuttall Consulting's approach to forecasting reinforcement in the next regulatory control period.

CitiPower contends that each of the reinforcement projects in the Revised Regulatory Proposal will be required as proposed in the next regulatory control period. CitiPower also maintains that the additional expenditure associated with the Metro 2012 and CBD Security of Supply projects are prudent and efficient.

9.1.4 Reliability and quality maintained capex

CitiPower maintains that the reliability and quality maintained capex forecasts included in its Initial Regulatory Proposal reasonably reflect the capex criteria. However, in this Revised Regulatory Proposal, CitiPower has adopted the AER's forecasts for its zone substation replacement, services replacement and fuse and surge diverters and transformer replacement programs.

CitiPower has provided in this Revised Regulatory Proposal additional details regarding key reliability and quality maintained capex programs for the next regulatory control period.

CitiPower does not consider that the Repex Model is capable of forecasting reliability and quality maintained capex that reasonably reflects the capex criteria. However, even if the

[544] AER, Final Customer Contributions Decision.

calibrated Repex Model is assumed to produce reasonable forecasts, the independent expert, PB, found that the Repex Model supports CitiPower's forecasts. Removing the two major drivers of the increase in CitiPower's forecast in the next regulatory control period (the fault level mitigation and reliability replacement programs), which PB considered should be evaluated as step change increases, PB concluded that the variation between the calibrated Repex Model and CitiPower's forecasts did not justify an adjustment to CitiPower's proposed forecast.

9.1.5 Environmental, safety and legal capex

CitiPower does not contest the AER's Draft Determination with respect to environmental, safety and legal capex. However, CitiPower contends that the AER should include 2009 actual data in its trend analysis and in forecasting the capex required in the next regulatory proposal by reference to historical expenditure.

9.1.6 SCADA and network control capex

The AER has not considered the circumstances of CitiPower's network in assessing its proposed SCADA and network control capex. CitiPower contends that its SCADA and network control programs in the next regulatory control period are required and provides in this Revised Regulatory Proposal additional information regarding key programs.

9.1.7 Non-network capex

CitiPower maintains that its proposed non-network – IT capex forecasts reasonably reflect the capex criteria.

CitiPower's expenditure in the current regulatory control period has been reduced relative to the ESCV's allowance in the 2006-10 EDPR as a result of the mandated AMI roll-out. CitiPower does not consider that an event, such as the AMI roll-out, will occur in the next regulatory control period such that CitiPower's non-network – IT capex should be constrained to the levels of its actual expenditure in the current regulatory control period. CitiPower rejects Nuttall Consulting's assertion that its IT systems are not 'agile' and submits that its proposed expenditure is required to ensure that its systems will remain 'agile' in the next regulatory control period.

The AER cannot discount the evidentiary value of the external cost benefit analysis CitiPower obtained from PwC in respect of its AMI leveraged project on the basis that it is not an internal assessment. As part of this Revised Regulatory Proposal, CitiPower has removed the one component from the AMI leveraged project that is able to be recovered through the S factor scheme. Even with this adjustment, PwC's review indicates that the AMI leveraged projects give rise to a significant expected net benefit. CitiPower rejects the AER's proposition that reinforcement capex deferrals would contribute to the funding of AMI leveraged projects.

CitiPower does not contest the AER's Draft Determination with respect to non-network – other capex.

9.2 Rule requirements

Clause 6.5.7(c) of the Rules provides that the AER must accept the forecast of required capex that is included in a building block proposal if the AER is satisfied that the total forecast capex for the regulatory control period reasonably reflects the capex criteria, namely:

- the efficient costs of achieving the capex objectives (set out in clause 6.5.7(a));
- the costs that a prudent operator in the circumstances of the relevant distribution business would require to achieve the capex objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

CitiPower set out its understanding of the interpretation of this statutory test in a letter to Mr Chris Pattas of the AER dated 4 May 2010. By way of summary, CitiPower considers that there may be a range of forecasts that reasonably reflect the capex criteria.[545] CitiPower appreciates that the AER may need to assess the methodology, approaches and input values used to develop the total forecast. However, the ultimate inquiry for the AER is whether the expenditure forecast meets the statutory test. After assessing the methodologies, approaches and input values underpinning the total forecast, the AER must 'take a step back' and consider whether the forecast falls within the range that reasonably reflects the capex criteria.

The AER must balance any competing effects on the total forecast of CitiPower's choices of methodology, approach or input values to determine whether, overall, those choices mean the AER is not satisfied that the total forecast falls within the range that reasonably reflects the capex criteria. The AER is not permitted to reject a total forecast put forward by CitiPower because one or more of the methodologies, approaches or inputs used to develop the forecast does/do not fall within the range that reasonably reflects the capex criteria without first satisfying itself that the compound effect of the choices is such that the total forecast does not reasonably reflect the criteria.

Where a forecast put forward by CitiPower does not fall within the range of forecasts that reasonably reflect the capex criteria, clause 6.12.3(f) of the Rules provides that the AER is only permitted to amend CitiPower's forecast to the extent necessary to enable it to be approved in accordance with the Rules, that is, for the AER to be satisfied that the amended forecast reasonably reflects the capex criteria. The AER is not permitted, for example, to reduce or increase a single component of the forecast without determining whether (in light of the other components of the forecast) the change is required to ensure that the total forecast falls within the range that reasonably reflects the capex criteria and is not permitted to reduce or increase the forecast to the level it or its consultants consider most appropriate.

This approach to the Rules is consistent with the philosophy underlying economic regulation under Chapter 6 that an economic regulator should not second guess the operational decisions of the regulated business. Provided, overall, the forecasts of capex reasonably reflect the capex criteria, the expenditure should be allowed by the AER.

[545] The notion that there can be no one correct or 'best' figure was recognised by the AEMC in its Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), p52. While the statement was made in the context of the regulation of TNSPs, it is equally applicable to the regulation of DNSPs.

In addition, the complexity of forecasting capex for a five year period means that the risk of regulatory error if a 'whole of expenditure' approach is not adopted by the AER may undermine the objective of the NEO, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety and security of supply of electricity and the reliability, safety and security of the national electricity system.[546]

9.3 CitiPower's Initial Regulatory Proposal

CitiPower's total forecast capex (by category) for the next regulatory control period included in its Initial Regulatory Proposal is set out in Table 9.1.

The forecast capex included in CitiPower's Initial Regulatory Proposal is discussed in further detail below, by capex category.

	$'000s (real 2010)					
Gross 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**
Less Customer Contributions	(40,434)	(41,291)	(35,732)	(34,036)	(34,767)	**(186,260)**
Net capex	**196,331**	**213,934**	**218,624**	**216,337**	**212,871**	**1,058,097**

Table 9.1 CitiPower's total capex forecasts for the 2011-15 regulatory control period included in the Initial Regulatory Proposal

9.4 AER's Draft Determination

The AER rejected the total forecast capex proposed in CitiPower's Initial Regulatory Proposal and substituted an estimate reflecting the recommendations of its consultant, Nuttall Consulting, and its own considerations. Specifically, the AER substituted (unescalated) total capex for 2011-15 which was the summation of the following:

[546] The highly complex nature of forecasting capital expenditure over a five year period was recognised by the AEMC in its Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), p52. While the statement was made in the context of the regulation of TNSPs, it is equally applicable to the regulation of DNSPs.

- new customer connections capex consistent with CitiPower's Initial Regulatory Proposal, except for the:
  - residential subdivisions and HV connections forecasts, for which the AER substituted average expenditure from 2006-09; and
  - forecasts associated with co-generation, which it disallowed entirely;
- reinforcement capex as forecast by Nuttall Consulting using the weighted average probability (derived from four project reviews and Nuttall Consulting's 'broader findings' in respect of CitiPower's forecasting methodology) plus the original ESCV estimate for the efficient cost of the CBD Security of Supply project and the estimate used in the regulatory test for the Metro 2010 project;
- reliability and quality maintained capex based on historical (2006-08) expenditure, with some allowance for the ageing of the network (based on the Repex Model findings), as forecast by Nuttall Consulting;
- environmental, safety and legal capex based on historical (2004-08) expenditure;
- SCADA and network control capex based on historical (2004-08) expenditure; and
- non-network capex as forecast by CitiPower.

The basis for the AER's Draft Determination, and CitiPower's response to the AER's Draft Determination, is discussed in more detail in the remainder of this Chapter.

9.5 Incorporation in Revised Regulatory Proposal of Draft Determination

CitiPower does not contest, and thus has incorporated in this Revised Regulatory Proposal, the AER's Draft Determination in respect of environmental, safety and legal capex (see further discussion below). CitiPower notes, however, that the AER should incorporate 2009 actual data in its consideration of these capex categories in the Final Determination. CitiPower also does not contest the AER's Draft Determination in respect of non-network – other capex, but notes that the AER should incorporate 2009 actual data in its consideration of these capex categories in the Final Determination.

CitiPower does not contest the AER's Draft Determination with respect to equity raising costs.[547]

CitiPower does not accept the AER's Draft Determination with respect to the remaining capex categories. These are discussed below, following a discussion of the general issues with the Draft Determination that CitiPower seeks to raise that cut across a number of capex categories.

9.6 General issues with the AER's Draft Determination

There are several issues in the AER's Draft Determination that are relevant to the AER's assessment of CitiPower's proposal for a number of capex categories. Specifically, CitiPower is concerned with the following:

[547] AER, Draft Determination, p439; AER, Draft Determination, Appendix N.

- the inconsistency of the AER's approach to the Draft Determination with Previous Distribution Determinations and decision making processes;
- the imposition of new evidentiary threshold requirements that are impermissible at law, and which are unduly onerous and demanding and ignore the difficulties which will ordinarily confront a regulated business in a price review process;
- the AER's failure to use 2009 actual data provided to it to model historical expenditure;
- the AER's 'revealed cost' approach to producing substitute forecasts of capex for the next regulatory control period;
- the failure by the AER to make the minimum adjustment to CitiPower's forecast necessary to enable the AER to approve the capex under the Rules, as required by clause 6.12.3(f);
- the lack of practical and relevant experience in operating an Australian distribution network of the authors of the Nuttall Consulting report relied on by the AER for the purposes of its Draft Determination in respect of capex; and
- the AER's incorrect findings that CitiPower's historical forecasting accuracy is poor.

These issues are discussed in this section of the Revised Regulatory Proposal.

9.6.1 Inconsistency with Previous Distribution Determinations and decision making processes

CitiPower is concerned by the lack of consistency in the AER's procedure and approach to making its Draft Determination compared to its approach to previous regulatory determinations in New South Wales, the Australian Capital Territory, Queensland and South Australia.

CitiPower contends that maintaining consistency in decision making was, and remains, a core objective of the establishment of the national framework for economic regulation of distribution and is characteristic of good administrative decision making.

For example, in assessing CitiPower's forecast reinforcement capex, the AER adopted forecasts prepared by Nuttall Consulting using a newly developed approach that is based entirely on engineering judgement, with no link to the demand forecasts that drive reinforcement capex. The approach has not been applied in any previous AER decision or any previous determination by the ESCV. Not only does CitiPower submit that it is a qualitative and subjective approach to forecasting, the approach is untested.

9.6.2 Imposition of evidentiary threshold requirements

In its Draft Determination, the AER sought to establish new evidentiary thresholds that are not reasonable and, in some instances, are not permissible at law. The thresholds the AER sought to establish are as follows:

- formal cost benefit analysis, including options analysis, and/or a risk assessment;
- internal cost benefit analysis (rather than external expert analysis);

- cost benefit analysis quantifying benefits and/or demonstrating a net benefit in circumstances where a DNSP's forecast capex is required to achieve compliance with its mandatory legal obligations; and
- a risk assessment where regulators have encouraged a risk management approach to compliance with mandatory legal obligations.

Each of these matters are discussed in turn below.

9.6.2.1 Formal cost benefit analysis as a threshold requirement

First, the AER sought to establish formal cost benefit analysis, including options analysis, and/or a risk assessment as a threshold requirement for the AER to be satisfied that a DSNP's forecast capex reasonably reflects the capex criteria. This is not legally permissible and involves an error of law.

In *Telstra Corporation Limited v Australian Competition Tribunal*, the Full Federal Court agreed with Telstra that the Australian Competition Tribunal had fallen into error by devising a set of rules (which it called a 'road map') for the making of its decision in that case, rather than directly applying the statutory test.[548] The Court stated:[549]

> '*Telstra submitted that, in reaching its ultimate conclusion that it was not satisfied that the making of the claimed exemption orders would promote the [long term interests of end-users], the Tribunal demanded evidentiary requirements and standards of Telstra which far exceeded those which were authorised by the relevant provisions of Pt XIC of the [Trade Practices Act 1974]. Thus, so it was submitted, the imposition of those requirements by the Tribunal demonstrated that the Tribunal had applied the wrong test in assessing the question of competition for the purpose of considering objective (c).*
>
> *…*
>
> *In our view, a critical part of the Tribunal's reasoning leading to its ultimate decision to set aside the exemption orders made by the ACCC was its holding that, in order for Telstra to satisfy the requirements of s 152AT(4) [of the Trade Practices Act 1974], it was necessary for Telstra to adduce empirical evidence before the Tribunal from which it would be possible to arrive at conclusions about market behaviour both as it existed at the time the exemptions were under considerations and in the future. It was this approach that led to the formulation and articulation of the road map in the Tribunal reasons…*
>
> *To impose a requirement of empirical evidence which addressed the matters set out in the road map as a minimum set of standards for an applicant for exemption to meet in a case such as the present is, as Telstra submitted, to apply the wrong test to the objective of competition required to be considered under s 152AB(2)(c).*
>
> *In our view, the Tribunal made an error of law in this regard. That error was fundamental to its decision. Accordingly, the Tribunal's decision ought be wholly set*

548 *Telstra v Australian Competition Tribunal* (2009) 175 FCR 201 at [174]-[175].
549 *Telstra v Australian Competition Tribunal* (2009) 175 FCR 201 at [171], [173]-[175].

> *aside on this ground pursuant to s 5(1)(f) of the ADJR Act and s39B of the Judicial Act.'*

CitiPower therefore submits that the AER cannot, at law, seek to establish threshold requirements (such as formal cost benefit analysis, including options analysis, and/or a risk assessment) for the AER to be satisfied that a DSNP's forecast capex reasonably reflects the capex criteria.

In addition, CitiPower notes that, as a practical matter, by seeking particular evidentiary material to achieve the necessary satisfaction under the Rules, the AER is setting the evidentiary threshold at an unreasonably high level. The AER's evidentiary threshold requirements are unduly onerous and demanding, and ignore the difficulties which will ordinarily confront a regulated business in a price review process.

9.6.2.2 Internal cost benefit analysis as a threshold requirement

Similarly, the AER's establishment of a DNSP's **own** cost benefit analysis as a threshold requirement for AER satisfaction that a DNSP's capex forecast reasonably reflects the capex criteria is not legally permissible and involves an error or law.[550]

As noted above, the Full Federal Court has ruled that an administrative decision maker cannot set evidentiary thresholds and impose these in place of the relevant statutory test of satisfaction.[551]

The statutory task with which the AER is charged under clause 6.5.7(c) of the Rules is to assess whether it can be satisfied that the DNSP's proposed capex reasonably reflects the capex criteria on the basis of the evidentiary material before it. In circumstances where this evidentiary material includes a detailed and rigorous cost benefit analysis performed by an independent expert, it is not open to the AER, acting reasonably, to conclude that it is not satisfied that the DNSP's proposed capex reasonably reflects the capex criteria because the cost benefit analysis before it was performed by an independent expert rather than the DNSP.

9.6.2.3 Cost benefit analysis for capex to achieve compliance with mandatory legal obligations as a threshold

It is not legally permissible for the AER to require a DNSP to adduce a cost benefit analysis demonstrating a net benefit or to '*quantify benefits and outcomes for consumers achieved by the forecast level of investment*'[552] as a precondition to AER satisfaction under clause 6.5.7(c) of the Rules in circumstances where the DNSP's forecast capex is required to achieve compliance with its mandatory legal obligations.

As noted above, the AER must accept a DNSP's total capex forecast if it is satisfied that the forecast reasonably reflects the efficient costs of achieving the capex objectives and the

[550] For example, the AER appears to have done this in respect of the AMI leveraged projects proposed by CitiPower as part of non-network – IT capex: AER, Draft Determination, p423.
[551] *Telstra v Australian Competition Tribunal* (2009) 175 FCR 201 at [173]-[175].
[552] For example, see AER, Draft Determination, p403.

costs a prudent operator would require to achieve the capex objectives (clause 6.5.7(c) of the Rules).

Achievement of the capex objectives includes compliance with all applicable regulatory obligations or requirements associated with the provision of standard control services (see clause 6.5.7(a) of the Rules). It follows that the AER has no discretion to refuse to accept a DNSP's forecast of capex required to achieve compliance with its mandatory legal obligations in circumstances where the AER is satisfied that the forecast reasonably reflects the efficient costs of compliance with those obligations. In particular, the AER has no discretion to refuse to accept a DNSP's forecast of capex required to achieve compliance with its mandatory legal obligations on the basis that the DNSP has not demonstrated a net benefit associated with that capex or has not quantified the benefits and outcomes for consumers.

This is consistent with the regulatory test under the Rules for transmission. Clause 5.6.5B(b) of the Rules states that a 'preferred option' (i.e. the option that maximises the present value of net economic benefit *'may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the* identified need *is for* reliability corrective action.' 'Reliability corrective action' is defined in Chapter 10 of the Rules to mean investment by a TNSP in a transmission network for the purposes of meeting the service standards linked to the technical requirements of schedule 5.1 or in 'applicable regulatory instruments'. 'Applicable regulatory instruments' is also defined in Chapter 10 of the Rules to mean all laws, regulations, orders, licences, codes, determinations and other regulatory instruments to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.

9.6.2.4 Risk assessment for capex required to achieve compliance with mandatory legal obligations as a threshold

Finally, it is not legally permissible for the AER to require a risk assessment as a precondition to AER satisfaction that a DNSP's forecast of capex required to achieve compliance with its mandatory legal obligations, on the basis that regulators of these obligations have adopted a 'risk based approach' to compliance.[553]

As noted, the AER must accept a DNSP's total forecast capex if it is satisfied that the forecast reasonably reflects the efficient costs of achieving the capex objectives and the costs a prudent operator would require to achieve the capex objectives (clause 6.5.7(c) of the Rules).

As also noted above, achievement of the capex objectives includes compliance with all applicable regulatory obligations or requirement associated with the provision of standard control services (clause 6.5.7(a) of the Rules). It follows that the AER has no discretion to refuse to accept a DNSP's forecast of capex required to achieve compliance with mandatory

[553] The AER indicated in respect of CitiPower's environmental, safety and legal capex forecasts, for example, that *'EPA Victoria and Energy Safe Victoria (ESV) have encouraged businesses to adopt a risk management approach to compliance'* and commented that CitiPower did not link its capex proposals to any risk assessment in support of the overall works program: AER, Draft Determination, pp401-2.

legal obligations in circumstances where the AER is satisfied that the forecast reasonably reflects the efficient costs of compliance with those obligations. In particular, the AER has no discretion to refuse to accept a DNSP's forecast of capex required to achieve compliance with its mandatory legal obligations for the reason that the DNSP has failed to adduce a risk assessment that supports the capex on the basis that the DNSP could bear 'compliance risk' (i.e. the risks associated with non-compliance with its legal obligations).

9.6.3 Use of 2009 actual capex

In its trend analysis in the Draft Determination, the AER used actual data from 2004-08 (and 2006-08 in the case of reliability and quality maintained capex). CitiPower notes that using data from 2004-08 or 2006-08 results in a systematic downward bias in the trend in CitiPower's actual expenditure over the current regulatory control.

In respect of environmental, legal and safety, SCADA and network control and non-network capex, the AER indicated that it had excluded 2009 and 2010 data provided by the DNSPs because it is *'forecast data and therefore not considered to be part of the historical trend.'*[554] On 30 April 2010, CitiPower provided to the AER its audited regulatory accounts for 2009. There is therefore no basis for excluding 2009 data from the analysis.

While not citing reasons for excluding 2009 data in respect of reliability and quality maintained expenditure, presumably the AER was reliant on Nuttall Consulting, who indicated that the 2009 audited data arrived too late for direct input into its review.[555] Again, given the audited regulatory accounts were provided to the AER on 30 April 2010, there is no reason for excluding the 2009 data from the analysis.

CitiPower notes that there is an inconsistency in the Draft Determination between the AER's treatment of 2009 actual data in its assessment of opex forecasts and its assessment of capex forecasts. Specifically, the AER had regard to unaudited 2009 costs provided to the AER on 10 March 2010 for the purposes of determining base year opex[556] but did not consider these unaudited costs for the purposes of assessing CitiPower's proposed capex. CitiPower notes that there is no basis for drawing this distinction.

While time pressures may have prevented the AER from having regard to 2009 unaudited accounts in considering CitiPower's capex forecasts, CitiPower expects that the AER will have regard to 2009 audited data in its Final Determination.

9.6.4 'Revealed cost' approach

In its Draft Determination, the AER largely adopted a 'revealed cost' approach to assessing CitiPower's proposed capex and forecasting substitute capex. The AER outlined its approach to the review of the Victorian distributors' forecast capex as follows:[557]

> *'The AER's approach in this review has been to review what costs may be considered efficient in the circumstances. In most instances where a need to substitute an alternative estimate of the likely cost has arisen, the AER has adopted a 'revealed*

554 AER, Draft Determination, pp400, 410, 419 and 429.
555 Nuttall Consulting, Report – Capital Expenditure*,* 4 June 2010, p23.
556 AER, Draft Determination, p238.
557 AER, Draft Determination, p288.

> *cost' approach. This approach considers that a well managed business responding to the regulatory incentive framework will not incur inappropriate costs. Therefore, for that DNSP, its historical costs in relation to an activity can be regarded as an efficient base for determining an alternative view for that activity.'*

The AER used actual expenditure for the period 2004-08 as a basis for forecasting capex in the environmental safety and legal and SCADA and network control categories of capex. The AER also used the historical expenditure trend as a basis for concluding that CitiPower's forecasts of non-network capex did not reasonably reflect the capex criteria (in the case of non-network - other capex, erroneously). Further, the AER used actual expenditure for the period 2006-08 (together with the Repex Model calibrated with 2006-08 data) to reject and substitute amounts for CitiPower's proposed reliability and quality maintained capex.

With the exception of customer connections capex (in respect of which, as discussed further below, CitiPower accepts a 'revealed cost' approach may be appropriate), historical expenditure is not a reasonable basis on which to prepare forecasts of capex for 2011-15 that reasonably reflect the capex criteria.

The AER acknowledged this in its Draft Determination. For example, the AER acknowledged that the variability of past expenditure in the environmental, legal and safety, SCADA and network control and non-network capex categories means that the '*historic trend cannot completely determine future requirements'*.[558]

As noted in CitiPower's Initial Regulatory Proposal,[559] the ESCV has also recognised that there are reasons why historical capex will not necessarily be indicative of capex going forward. The ESCV stated in its 2006-10 EDPR that it:[560]

> *'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.'*

CitiPower notes that it expects both maximum demand and the average asset age of the network to increase in the next regulatory control period (see Chapters 4 and 9). CitiPower also notes that the risks its network will face in the next regulatory control period will not be the same as the risks it faced in the past. Accordingly, CitiPower is concerned that the Draft Determination fails to provide for capex that would be required by an efficient and prudent operator to meet the capex objectives.

558 AER Draft Determination, pp399, 409, 419 and 429.
559 Initial Regulatory Proposal, p143.
560 ESCV's 2006-10 EDPR, p269.

9.6.5 Adjustments to CitiPower's forecasts

As noted above, clause 6.12.3(f) of the Rules provides that the AER is only permitted to amend CitiPower's forecast to the extent necessary to enable it to be approved in accordance with the Rules, that is, for the AER to be satisfied that the amended forecast reasonably reflects the capex criteria.

Aside from cursory comments that the AER considered its adjustment to be the minimum adjustment necessary, there is no evidence in the Draft Determination of the AER seeking to identify the minimum adjustment necessary. The AER has simply identified and adopted point estimates based on Nuttall Consulting's recommendations, including those estimates based on historical expenditure trends and the Repex Model.

In order to comply with the Rules, CitiPower submits that the AER must adjust the forecasts included in CitiPower's Revised Regulatory Proposal to the minimum extent necessary to reach satisfaction under the Rules.

9.6.6 Experience of Nuttall Consulting

On 22 June 2010, CitiPower requested (by email) copies of the curriculum vitae of each of the authors of the Nuttall Consulting report. CitiPower was advised by the AER by email on 25 June 2010 that, given Mr Nuttall's unavailability, the relevant curriculum vitae would be provided prior to, or in conjunction with, the AER's Final Determination.

It is CitiPower's understanding that the authors of the Nuttall Consulting Report – Capital Expenditure of 4 June 2010 may not have adequate practical experience in operating an Australian distribution network. In light of this, and in the context of Nuttall Consulting's recommendations significantly contributing to the AER's capex cuts of in excess of $2,096 million across all Victorian DNSPs in the next regulatory control period, the findings of Nuttall Consulting should be carefully scrutinised.

9.6.7 Historical accuracy of CitiPower's forecasts

In its Draft Determination, the AER had regard to the past forecasting performance of Victorian DNSPs.[561] The AER concluded that DNSPs' capex forecasts tend to systematically over estimate actual capex.[562]

However, a DNSP's actual expenditure will necessarily be constrained by the allowance it receives in the relevant regulatory decision. Regulated businesses do not have access to an endless pool of capital, and thus they are constrained by the revenue allowed by the regulator.

[561] AER, Draft Determination, pp291-2, 315, 344-5, 409, 418 and 428. The AER indicated that it considered CitiPower's historical accuracy of forecasting on the basis of clauses 6.5.7(e)(5) of the Rules: AER, Draft Determination, p291 (footnote 22). However, this section of the Rules does not justify an assessment of past forecasting accuracy. Clause 6.5.7(e)(5) of the Rules provides that the AER must have regard to the actual and expected capex of the distribution network service provider during any preceding regulatory control periods. That is, rather than requiring a comparison of past forecast and actual expenditure, the section requires the AER to have regard to: 1) actual capex incurred in past and current regulatory control periods; and 2) expected capex in the remaining years of the current regulatory control period in respect of which there are no actual expenditure figures.

[562] AER, Draft Determination, pp291-2.

In comparing CitiPower's historical capex to the benchmark set by the ESCV (set out in Table 9.2 below), CitiPower's expenditure is below the ESCV's aggregate benchmark in the years 2006 and 2007. However, the variance almost exclusively relates to reinforcement expenditure, in particular, the deferral of the Metro 2012 project. This was discussed in more detail in CitiPower's Initial Regulatory Proposal.[563] In addition, actual expenditure in 2006-09, coupled with expected expenditure in 2010, exceeds the total benchmark set by the ESCV.

	$'000 2010					
Capex	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
Actual	102,306	94,326	115,798	124,706	147,985	585,121
Regulatory allowance	120,186	114,715	113,054	124,105	105,224	577,285
Difference	**(17,881)**	**(20,389)**	**2,744**	**602**	**42,761**	**7,837**

Table 9.2 Comparison of gross capex over 2006-10 to ESCV allowance

Finally, contrary to the AER's conclusion that DSNPs' capex forecasts tend to systematically overestimate capex,[564] as shown in Table 9.2 above, CitiPower's 2009 actual capex was consistent with its 2009 forecasts.

9.7 New customer connections capex

9.7.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower included, in the total forecast capex, new customer connections capex net of customer contributions.

9.7.1.1 Gross customer connections

CitiPower prepared its gross new customer connections capex forecasts for each year of the next regulatory control period by drawing on historic expenditure at an activity code level. The methodology used by CitiPower was outlined in the Initial Regulatory Proposal.[565]

CitiPower considers that historical capex can be an appropriate basis on which to determine gross customer connections forecast capex because the drivers of customer connections remain relatively constant across regulatory control periods.

9.7.1.2 Customer contributions

CitiPower indicated in its Initial Regulatory Proposal that, in calculating customer contributions, it had assumed that it will continue to:

- require customer contributions for new connections when it is expected that the customer 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 ESCV's Guideline 14.[566]

[563] Initial Regulatory Proposal, pp145-6.
[564] AER, Draft Determination, p292.
[565] Initial Regulatory Proposal, pp94-8.

After lodging its Initial Regulatory Proposal, CitiPower raised concerns with the AER that, in forecasting capital contributions, CitiPower had used the 2009 Contribution Rate and had only adjusted the 2009 Contribution Rate to account for expected changes to the MCR.[567] The Contribution Rate is also a function of three other factors: the P_0, X factor and WACC. The values underpinning the 2009 Contribution Rate are those set out in the ESCV's 2006-10 EDPR. These values are expected to change significantly, however, with the AER's Final Determination in this price review.

CitiPower indicated to the AER that it would propose revised customer contribution forecasts in its Revised Regulatory Proposal that are consistent with:[568]

- ESCV's Guideline 14, including its understanding of the AER's interpretation of ESCV's Guideline 14 following the AER's Draft Decision, Benchmark Upstream Augmentation Charge Rates for CitiPower's Network of 19 February 2010; and
- the proposed P_0, X factor and WACC values included in the Revised Regulatory Proposal.

9.7.2 AER's Draft Determination

9.7.2.1 Gross customer connections

The AER rejected the gross customer connections forecast put forward by CitiPower because:[569]

- CitiPower did not have regard to the likely number of connections or jobs;
- using actual reported expenditure from the current regulatory control period (i.e. 2006-09) provides a more accurate basis to forecast expenditure than one year of data;
- growth in the total number of customers is not a reasonable indicator of growth in gross customer connections capex as growth in connections expenditure should only occur if the number of new connections or jobs is forecast to change; and
- the AER did not accept CitiPower's proposed classification of a number of services as standard control.

Regarding the classification of services, the Draft Determination referred to CitiPower including in its proposed customer connections forecasts capex relating to services the AER identified as *'labour and materials for routine connections'*.[570] CitiPower has assumed the AER is referring to capex in function codes 114 and 115.

CitiPower's Initial Regulatory Proposal assigned function codes 114 and 115 to standard control customer connection capex. However, because the AER did not accept the classification of services under these codes as standard control services, the AER assigned function codes 114 and 115 to alternative control, presumably to routine connections.

The AER substituted average actual expenditure from 2006-09 for residential and business subdivision projects and low voltage connections with customer supply capacity at greater

566 Initial Regulatory Proposal, p94.
567 Letter to Mr Blair Burkitt, Director Network Regulation South, AER, 19 April 2010, pp5-7.
568 Letter to Mr Blair Burkitt, Director Network Regulation South, AER, 19 April 2010, p8.
569 AER, Draft Determination, pp306-7.
570 AER, Draft Determination, p307.

than 500kVA.[571] The AER noted there was insufficient evidence that a major connection at the former Carlton and United Breweries site (Swanston St, Melbourne) proposed by CitiPower would take place within the proposed timing and thus considered that allowing average historic expenditure provides a reasonable forecast of expenditure.[572]

The AER also indicated that because it did not accept CitiPower's proposed classification of fault level mitigation for new embedded generators as part of standard control capex, it removed the proposed gross customer connections capex and customer contributions for these services (i.e. the forecast for function code 118) from the forecast new customer connections capex in the Draft Determination.[573]

9.7.2.2 Calculation of customer contributions

In the Draft Determination, the AER noted the issue of the Victorian DNSPs' treatment of the X factor in the proposed calculation of customer contributions and inserted a 'place holder' for the purposes of the Draft Determination, indicating that DNSPs must revise their calculations to ensure compliance with ESCV's Guideline 14 in their revised regulatory proposals.[574]

9.7.3 CitiPower's response to the AER's Draft Determination

CitiPower has amended its customer connections capex forecasts in this Revised Regulatory Proposal to:

- respond to the AER's concerns with its calculation of gross customer connections capex; and
- reflect the AER's Final Customer Contributions Decision, which was published after the Draft Determination.

CitiPower attaches to this Revised Regulatory Proposal its Customer Capex Model and Customer Contributions Rate Model, which give effect to the above.[575]

CitiPower submits that its revised customer connections capex forecasts will result in total capex forecasts that reasonably reflect the capex criteria.

9.7.3.1 Gross customer connections

In response to the AER's Draft Determination, CitiPower has revised its gross customer connections forecasts for the next regulatory control period.

For all function codes except function code 118, CitiPower has been unable to find a significant historic relationship between volume of projects and change in number of customers or regional economic growth. Therefore, in the absence of any identifiable driver of volume of projects, CitiPower has assumed that the 2010-15 annual volume of projects will be equal to the average 2006-09 annual volume of projects.

[571] AER, Draft Determination, p307.
[572] AER, Draft Determination, p307.
[573] AER, Draft Determination, p307.
[574] AER, Draft Determination, pp305-308.
[575] Customer Capex Model (Attachment 7 to this Revised Regulatory Proposal) and Customer Contributions Rate Model (Attachment 8 to this Revised Regulatory Proposal).

The 2010-15 annual unit rates, exclusive of input escalation, overheads and margins, are forecast to be equal to the average 2006-09 annual unit rates (in real terms). Therefore, the total annual cost, exclusive of input escalation, overheads and margins, is forecast to be equal to the average 2006-09 annual cost (in real terms).

The AER should accept CitiPower's customer connections capex forecasts because they are based on historic expenditure from more than one year (i.e. 2006-09).

Clause 7.1 of CitiPower's Electricity Distribution Licence[576] requires it to offer embedded generation connection services. The forecast expenditure for function code 118 relates to embedded generators that are not classified as small, in accordance with ESCV's Guideline 15 section 6 and therefore not covered by approved generation charges as contemplated in ESCV's Guideline 15, clause 3.2.1.

CitiPower expects to receive a number of requests over the next regulatory control period for the connection of embedded generation. As a consequence, it is incorrect for the AER to set this function code allowance to zero. CitiPower has included in this Revised Regulatory Proposal an amount against function code 118 to allow for a gradual ramp up in requests for connection of embedded generators over the next regulatory control period, based on average (gross) connection costs of $503,000.

9.7.3.2 Function codes 114 and 115

In an email to the AER of 22 February 2010, CitiPower set out descriptions of various function codes, including 114 and 115. The descriptions for function codes 114 and 115 were as follows:

- **New connections servicing materials:** All costs of materials associated with the works necessary to supply and connect new overhead, underground and URD services.
- **New connections servicing labour:** includes:
    - installation costs relating to the provision of overhead services for supply upgrades;
    - installation costs relating to the provision of overhead servicing and connection from line of mains;
    - installation costs relating to the service provision of current transformers;
    - installation costs relating to the connection of underground service cable to customer's mains; and
    - processing of connection requests for new servicing activities.

CitiPower considers that the AER has made an error in removing function codes 114 and 115 from standard control and allocating them to alternative control. CitiPower takes this view based on the following:

- function codes 114 and 115 capture the costs of miscellaneous customer connection services which do not fit into the other customer connection categories;

[576] As varied on 31 August 2005 (Attachment C0153 to the Initial Regulatory Proposal).

- CitiPower's auditors (Deloitte) have signed off that these costs are customer connection capex and not a routine connection excluded service cost for the purposes of the 2006-09 regulatory accounts;
- the Draft Determination states that *'The AER agrees with SP AusNet that the previous classification of routine connections under the ESCV regime as excluded services is analogous to their classification as alternative control services under the NER'*.[577] The AER has thus confirmed the allocation of costs in respect of routine connections as signed off by Deloitte is appropriate; and
- CitiPower's approved CAM classifies these costs as standard control.

CitiPower notes that the routine connection costs reported in the 2009 regulatory accounts are already significantly greater than the routine connection revenue implied by the charges proposed in the Draft Determination. By including function codes 114 and 115, the AER is implying that CitiPower's costs of providing a routine connection are at least double the AER's Draft Determination benchmark. This is clearly at odds with the AER's assertion that the Victorian DNSPs are efficient.

Finally the miscellaneous nature of services provided under function codes 114 and 115 do not allow CitiPower to provide volumes for these function codes. For the purposes of forecasting costs in function codes 114 and 115, CitiPower has assigned an annual volume of one over 2006-09 and forecast gross capex in accordance with the methodology set out in the previous section (i.e. for all function codes other than function code 118).

9.7.3.3 Customer contributions

As noted above, subsequent to CitiPower's correspondence with the AER regarding customer contributions and the AER's Draft Determination, the AER issued a final decision regarding CitiPower's upstream augmentation charges. The Final Customer Contributions Decision confirmed the AER's approach to ESCV's Guideline 14, as outlined in its Draft Decision, *Benchmark Upstream Augmentation Charge Rates for CitiPower's Network*, 19 February 2010.

As foreshadowed in its letter of 19 June 2010, CitiPower has amended its forecasts of customer contributions in this Revised Regulatory Proposal to ensure consistency with ESCV's Guideline 14 and the P_0, X factor and WACC values included in the Revised Regulatory Proposal. CitiPower forecast customer contributions for each of those function codes that are likely to be affected by a change in the MCR, P_0, X or WACC by:

- starting with the average 2006-09 Contribution Rate;
- using a sample of actual connection projects in each function code, calculating the expected change in the Contribution Rate if:
  - a reduction in the MCR consistent with the Final Customer Contributions Decision is applied; and
  - the P_0, X factor and WACC values included in this Revised Regulatory Proposal are applied.

[577] AER, Draft Determination, p23.

- calculating the forecast Contribution Rate as the average 2006-09 Contribution Rate adjusted for the impact of the reduction in the MCR and the application of the P_0, X factor and WACC values included in this Revised Regulatory Proposal; and
- applying the adjusted Contribution Rate to forecast gross new customer connections capex over the next regulatory control period.

Given the Contribution Rate is dependent on P_0, X factor and WACC values, CitiPower observes that if the AER rejects any of these values included in this Revised Regulatory Proposal, then the AER will need to calculate the impact on the Contribution Rate of the values it substitutes, and thus the impact of these values on customer contributions in the next regulatory control period. As noted above, CitiPower has attached to this Revised Regulatory Proposal its Customer Contribution Rate and Customer Capex Models, which the AER can use for this purpose.[578]

9.7.4 CitiPower's Revised Regulatory Proposal

The new customer connections capex forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 9.3 below.

	$'000 (real 2010)					
Expenditure category	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
Gross new customer connections	60,022	62,278	62,577	64,203	66,150	**315,231**
Customer contribution	(9,576)	(10,885)	(11,016)	(11,653)	(12,314)	**(55,444)**
Net new customer connections	**50,446**	**51,393**	**51,561**	**52,549**	**53,837**	**259,787**

Table 9.3 Forecast customer capex included in CitiPower's Revised Regulatory Proposal

9.8 Reinforcement capex

9.8.1 CitiPower's Initial Regulatory Proposal

Reinforcement capex relates to capital works that are required to augment CitiPower's:

- sub-transmission network (i.e. assets directly connected to transmission connection points, made up of 66kV sub-transmission lines and zone substations); and
- high voltage and low voltage network (i.e. 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 loading levels increase. This can affect their long term serviceability. Reinforcement capex is designed to enable CitiPower to augment its network 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.

For sub-transmission projects, CitiPower's reinforcement capex is therefore driven by maximum demand forecasts and the resultant energy at risk. For low voltage and high

[578] Attachments 7 and 8 to this Revised Regulatory Proposal.

voltage parts of the network, reinforcement capex is driven by utilisation. The methodology for forecasting reinforcement capex was set out in the Initial Regulatory Proposal.[579]

Subsequent to the Initial Regulatory Proposal, CitiPower provided to the AER (among other things) energy at risk calculations for each sub-transmission and zone substation.[580]

9.8.2 AER's Draft Determination

The AER rejected CitiPower's methodology for forecasting reinforcement capex on the basis that the process adopted by CitiPower for a bottom-up build of reinforcement capex does not provide a reasonable unbiased estimate of efficient future reinforcement capex.[581]

The AER reached this view based on the following conclusions of Nuttall Consulting:

- The use of a probabilistic approach that weighs the forecast value of expected energy at risk against the costs to reduce energy at risk in forecasting reinforcement capex is reasonable but the implementation of this approach by CitiPower results in a systematic upward bias in the resultant estimate of future reinforcement capex.[582] Specifically, Nuttall Consulting concluded that CitiPower's approach to forecasting:
  - does not take account of synergies between projects (rather it involves a simple summation of total projects planned), whereas detailed cost/benefit analyses would allow for synergies between projects;[583] and
  - does not adequately consider options that may involve lower cost, whereas detailed cost/benefit analyses may determine that deferral of projects or lower cost alternatives are more efficient options.[584]
- CitiPower's use of a load profile from 2001-05 will result in a systematic upward bias in its estimates of future prudent and efficient reinforcement capex.[585] This is because, being from an older time period, the load profile is relatively flat.[586]
- CitiPower's assumptions regarding transformer outage rates were overstated, and there is scope for these to be reduced via optimisation of spares and contracting with transformer manufacturers.[587]

The AER also concluded that:

- CitiPower's use of overstated maximum demand forecasts in forecasting reinforcement capex will result in a systematic upward bias in the estimate of prudent and efficient reinforcement capex.[588]
- CitiPower's process for a bottom-up build of reinforcement capex was based on factors other than a probabilistic assessment, which were not demonstrated to result in a forecast of efficient reinforcement capex. Specifically, the AER considered that, in many cases, the timing of major reinforcement capex projects was based on a number

[579] Initial Regulatory Proposal, pp81-6 and 396-409, 418-21.
[580] The calculations were provided to the AER on CD on 27 January 2010.
[581] AER, Draft Determination, pp334-7.
[582] AER, Draft Determination, p321.
[583] AER, Draft Determination, p319.
[584] AER, Draft Determination, p322.
[585] AER, Draft Determination, pp321-2.
[586] AER, Draft Determination, pp321-2.
[587] AER, Draft Determination, p318.
[588] AER, Draft Determination, p322.

of factors in addition to the cost of energy at risk and was heavily reliant on the judgement of planning engineers.[589]

Finally, based on Nuttall Consulting's assessment, the AER was not satisfied as to the likelihood of CitiPower's expenditure being required as proposed in the next regulatory control period.[590] Nuttall Consulting concluded that there was a low probability (39 per cent) of CitiPower's reinforcement capex (excluding the CBD Security of Supply and Metro 2012 projects) being required as proposed.[591]

Nuttall Consulting also concluded that CitiPower had not adequately demonstrated the efficiency of the proposed expenditure in excess of the ESCV original estimate for the efficient cost of the CBD Security of Supply project and the estimate used in the regulatory test for the Metro 2012 project.[592]

In place of CitiPower's reinforcement capex forecasts, the AER substituted forecasts prepared by Nuttall Consulting.[593] To determine reinforcement capex for the next regulatory control period Nuttall Consulting:[594]

- reviewed four of the projects proposed by CitiPower and assigned, a probability (low – 33 per cent, moderate – 50 per cent, moderate/high – 70 per cent or high – 90 per cent) that the project expenditure would be required at the level and time proposed. As well as reflecting the project reviewed, the probability assigned to each project allowed for Nuttall Consulting's *'broader findings from the methodology review and expenditure analysis'*;
- applied the average weighted probability to CitiPower's proposed total reinforcement capex excluding the CBD Security of Supply and Metro 2012 projects;
- developed an annual expenditure profile, using:
    - average annual expenditure over 2006-08 as a base-line for the expenditure; and
    - a constant annual expenditure growth rate; and
- added the ESCV original estimate for the efficient cost of the CBD Security of Supply project and the estimate used in the regulatory test for the Metro 2012 project (each with adjustments for labour and materials escalation).

Following this process, Nuttall Consulting recommended reducing CitiPower's forecast of reinforcement capex by 61 per cent.[595]

[589] AER, Draft Determination, p335.
[590] AER, Draft Determination, p322. The AER accepted Nuttall Consulting's findings in reaching its conclusion on CitiPower's proposed reinforcement capex: AER, Draft Determination, p336.
[591] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p101.
[592] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p100.
[593] AER, Draft Determination, p336.
[594] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp55-56, 99-100.
[595] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p101; AER, Draft Determination, p336.

9.8.3 CitiPower's response to the AER's Draft Determination

9.8.3.1 Summary

CitiPower submits that its approach to forecasting reinforcement capex does not result in a systematic upward bias in the estimate of future prudent and efficient reinforcement capex. This is because:

- its methodology does not result in a systematic upward bias in the estimate. Specifically:
  - CitiPower's internal planning criteria incorporate the same criteria as CitiPower's governance documents, which Nuttall Consulting concluded would be expected to deliver prudent and efficient outcomes;
  - CitiPower's processes take into account synergies and result in forecasts that are economically justified; and
  - overall, SKM found that CitiPower's energy at risk modelling (including its load duration and transformer outage rate assumptions) is likely to **understate** energy at risk;[596] and
- the zone substation level maximum demand forecasts used to prepare the reinforcement capex forecasts are consistent with NIEIR's system maximum demand forecast (see Chapter 4). Thus the maximum demand forecasts used to forecast reinforcement capex are not likely to result in a systematic upward bias in the estimate.

CitiPower rejects Nuttall Consulting's approach to forecasting reinforcement in the next regulatory control period.

CitiPower contends that each of the reinforcement projects in the Revised Regulatory Proposal will be required as proposed in the next regulatory control period. Additional details of CitiPower's proposed reinforcement projects are set out below and are included in material project templates.[597]

CitiPower also maintains that the additional expenditure associated with the Metro 2012 and CBD Security of Supply projects are prudent and efficient.

9.8.3.2 CitiPower's methodology for forecasting reinforcement capex

CitiPower's methodology for forecasting reinforcement capex does not result in a systematic upward bias in the estimate of future prudent and efficient reinforcement capex. The reasons for this are discussed below.

Internal planning criteria

Nuttall Consulting concluded that CitiPower's governance documentation '*demonstrates well-developed capital governance processes and practices that, if followed, would be expected to deliver prudent and efficient outcomes for its stakeholders.*'[598] CitiPower's internal planning criteria incorporate the same criteria as CitiPower's governance

[596] SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p21.
[597] Included in Attachment 161 to this Revised Regulatory Proposal.
[598] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p101; AER, Draft Determination, p297.

documents. The rigour of the analysis applied by CitiPower in its forecasting and its governance processes is the same. Any changes in project scope and timing are the result of new information, rather than more detailed analyses being conducted.

Synergies

CitiPower takes synergies into account in developing its forecasts of reinforcement capex. For example, CitiPower's Transformer and Distribution Circuit Breaker Strategic Replacement Program[599] clearly identifies where replacement has been deferred to coincide with augmentation.

Nuttall Consulting recognised that, in some circumstances, projects may be advanced or their scopes increased as they move through DNSPs' capital governance processes.[600] Nuttall Consulting concluded, however, that this will most likely result in overall expenditure being less than the simple summation of the project plans.[601] CitiPower maintains that project scopes and timing move in both directions as projects move through CitiPower's governance processes. As noted above, this reflects changes in relevant circumstances, rather than the application of a more detailed analysis.

Cost benefit analyses

To assist the AER with its assessment of CitiPower's proposed reinforcement capex, CitiPower has conducted cost benefit analyses in respect of the four major projects reviewed by Nuttall Consulting for its probability assessment. These cost benefit analyses are set out in the reinforcement capex material projects templates included in Attachment 161 to this Revised Regulatory Proposal. The cost benefit analyses show that the projects included in the Revised Regulatory Proposal are economically justified. CitiPower notes that, following the reduction in the maximum demand forecasts in the Fisherman's Bend area (discussed in Chapter 4), one project reviewed by Nuttall Consulting (the third transformer at SB) is no longer proposed in the next regulatory control period.

CitiPower submits that the cost benefit analyses conducted for these major projects demonstrates that CitiPower's internal processes for forecasting reinforcement capex are likely to identify reinforcement projects for the next regulatory control period that are economically justified and result in total forecasts that are prudent and efficient.

Energy at risk modelling

CitiPower's use of a load profile from 2001-05 will not result in a systematic upward bias in its estimate of prudent and efficient reinforcement capex. As noted by the independent expert engaged by CitiPower to consider its and Nuttall Consulting's load duration curve assumptions, SKM, Nuttall Consulting's analysis is flawed because it places significant weight on the shape of the top one per cent of the summer load duration curves, whereas, in SKM's experience, this part of the curve has little impact on the energy at risk.[602] In any

[599] Attachment C0106 to the Initial Regulatory Proposal.
[600] Nuttall Consulting, Report – Capital Expenditure*,* 4 June 2010, pp51-2.
[601] Nuttall Consulting, Report – Capital Expenditure*,* 4 June 2010, p51.
[602] SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p19.

event, SKM's analysis indicates that CitiPower's capex reinforcement forecasts are not sensitive to the load profile selected.[603]

CitiPower's assumption of a 2.6 month outage duration for transformers is reasonable for planning purposes. As recognised by Nuttall Consulting and SKM, the rate is consistent with long standing industry standard.[604] In addition, the independent expert SKM concluded that CitiPower's transformer outage duration assumptions are more conservative than international experience, which suggests that Citipower may be underestimating the value of energy at risk in their calculations.[605]

The 2.6 month duration is a weighted average of the duration of a catastrophic failure and the duration of other, less catastrophic, failure modes. The duration intervals are estimates of the time taken to assess the transformer on site following a fault. Certain diagnostic tests are needed to determine whether the transformer can be repaired on site or needs to be sent to a manufacturer's facility for repair. A suitable spare could be determined to install in the station. However, this might require the construction of different foundation and bundling works. Primary and secondary design works are also likely to be required to assess the characteristics of the particular zone substation. If irreparable, and no in-service units are identified for relocation, a new transformer would be ordered and manufactured. There are very long lead times in procuring transformers (up to 18 months).[606]

Nuttall Consulting suggested that transformer outage durations could be reduced through optimisation of spares and through contracting arrangements with manufacturers. However, in suggesting these options, Nuttall Consulting failed to consider the cost associated with implementing these measures. Nuttall Consulting's proposed options are not sustainable at this time and should not be accepted by the AER as a basis for concluding that CitiPower's transformer outage duration assumptions are unreasonably high.

The reduction of outage durations through the measures suggested by Nuttall Consulting would not be efficient or prudent measures for CitiPower to pursue at this time. Nuttall Consulting concluded that CitiPower is relatively efficient.[607] If follows that, if it was efficient to hold spares or to seek to negotiate special terms with manufacturers, CitiPower would already be doing this.

There are significant costs associated with implementation of the measures for reducing outage durations proposed by Nuttall Consulting. CitiPower notes there are 12 'families' or 'generic types' of power transformers currently in service (see Table 9.4 below). The different types involve different voltage ratios, tap-changing ranges, vector groups, output ratings, connection arrangements and cooling arrangements etc.

[603] SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), pp18-9.
[604] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p52; SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p21.
[605] SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p16.
[606] CitiPower, Zone Substation Transformers Asset Management Plan, November 2009 (Attachment C0104 to the Initial Regulatory Proposal), p25.
[607] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p21; AER, Draft Determination, p285.

Voltage (kV)	Size (MVA)	HV/LV Terminations	Cooling Mode
22/6.6	7.5	Cable/Cable	Air
22/6.6	10/13.5	Cable/Cable	Air
22/6.6	10/13.5	Bushing/Cable	Air
22/11	10/13.5	Cable/Cable	Air
22/11	10/13.5	Bushing/Cable	Air
66/6.6	10/13.5	Bushing/Cable	Air
66/6.6	20/27	Bushing/Cable	Air
66/11	20/27	Bushing/Cable	Air
66/11	30	Bushing/Cable	Water
66/11/11	55	Bushing/Cable	Water
66/11/11	55	Bushing/Cable	Air
66/11	60	Bushing/Cable	Water

Table 9.4 CitiPower's power transformer generic types

Given the above range of transformers, it would be not be efficient for CitiPower to seek to hold spares of each. CitiPower notes that while it is seeking to reduce outage durations by improving the interchangeability of transformers between sites through standardisation,[608] the benefits of this strategy will take a period significantly longer than the next regulatory control period to materialise.

Similarly, it would be very difficult and/or costly to enter into contracts with manufacturers to reduce outage durations. This is because the units would have to be specifically designed for each transformer type in CitiPower's network. CitiPower would then have to negotiate a holding or leasing arrangement for the manufacturer to construct a holding facility, which complies with the range of regulatory and legislative obligations regulating the containment and drainage of oil filled equipment, to store and maintain the transformer units.[609] This would not be costless. Given the number of transformer types CitiPower could potentially be required to replace in a given period, the additional costs associated with this approach would be significant.[610]

[608] CitiPower, Zone Substation Transformers Asset Management Plan, November 2009 (Attachment C104 to the Initial Regulatory Proposal), p25.
[609] The sources of these obligations are outlined in the Initial Regulatory Proposal, p120.
[610] CitiPower notes that the additional costs associated with replacing failed transformers with another type of transformer (i.e. a transformer of a different type to the failed transformer) means that not all failed transformers can be replaced with a standardised transformer at this time. The need for CitiPower to hold a significant number of transformer types as spares (under Nuttall Consulting's proposal) is therefore not alleviated by its strategy to standardise its transformer population.

Overall, SKM indicated that CitiPower's approach to energy at risk modelling is likely to **understate** energy at risk because:[611]

- CitiPower's energy at risk analysis uses the 50 per cent PoE demand forecasts, whereas in practice CitiPower must take into account the possibility of an extreme summer and the possible impact on climate change on both the maximum temperatures and duration of hot spells;
- CitiPower models energy at risk using fault rates for power transformers, but not the energy at risk for other equipment faults in the substations (e.g. cables, switchgear). SKM considered that the risk of catastrophic failure of indoor 11/22kV switchgear is relatively high, and involves lengthy repair and restoration times; and
- CitiPower uses transformer fault rates which are intended to reflect transformer outages where actual damage occurs to the transformer. There are other outages that occur where energy is at risk, but for which no damage has occurred and supply is restored after several hours, and these faults are not modelled by CitiPower.

Maximum demand forecasts

As noted in Chapter 4, the AER rejected the maximum demand forecasts proposed by CitiPower in its Initial Regulatory Proposal, and instead substituted maximum demand forecasts that it had reconciled with the maximum demand forecasts produced by NIEIR in November 2009. The maximum demand forecasts used to develop CitiPower's reinforcement capex forecasts in this Revised Regulatory Proposal are those included in the Initial Regulatory Proposal, except in relation to the four zone substations in the Fishermans Bend area. As discussed in Chapter 4 of this Revised Regulatory Proposal, CitiPower reduced these forecasts in light of the lower than expected maximum demand at these zone substations in 2009-10. CitiPower's revised spatial maximum demand forecasts resulted in one major project, the third transformer at the SB zone substation, being moved beyond 2011-15.[612]

The maximum demand forecasts used to forecast CitiPower's reinforcement capex are consistent with NIEIR's updated system level maximum forecasts. Accordingly, the spatial maximum demand forecasts used to forecast reinforcement capex are not likely to result in a systematic upward bias in the forecasts of reinforcement capex.

Other matters raised by the AER

CitiPower observes that the AER did not identify the factors in addition to energy at risk that it considered influenced the timing of the projects reflected in CitiPower's forecasts of reinforcement capex. In any event, CitiPower develops its sub-transmission reinforcement capex forecasts solely by reference to energy at risk. In respect of its high and low voltage network, CitiPower considers the utilisation of the network. The only exceptions are where, as discussed above, synergies can be extracted from reliability and quality maintained capex.

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[611] SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p22.
[612] CitiPower, Network planning proposal, SB 3rd Transformer, 5 July 2010 (included in Attachment 161 to this Revised Regulatory Proposal).

It is unclear what the AER means by its comments that CitiPower did not establish a clear link between the exercise of engineering judgment and the economic efficiency of the resultant forecast of reinforcement capex.[613] As noted above, forecast sub-transmission reinforcement capex is driven by energy at risk and low and high voltage network by utilisation (with deviations only to account for potential synergies). In any event, as highlighted above, the cost benefit analyses conducted by CitiPower in forecasting reinforcement capex are set out in the material projects templates relating to major reinforcement capex projects,[614] demonstrate the economic efficiency of these forecasts of reinforcement capex, and thus support the methodology used by CitiPower.

9.8.3.3 Reinforcement projects proposed by CitiPower

As noted above, Nuttall Consulting's consideration of the reinforcement projects proposed by CitiPower involved:

- in respect of CBD Security of Supply and Metro 2012 projects, consideration of the additional expenditure proposed by CitiPower (i.e. above the amounts used/approved through the ESCV's review processes); and
- consideration of four major projects proposed by CitiPower.

CBD Security of Supply and Metro 2012 projects

Nuttall Consulting, and therefore the AER, concluded that CitiPower did not adequately demonstrate the justification for the additional expenditure on its CBD Security of Supply and Metro 2012 projects.[615]

CitiPower observes that Nuttall Consulting's recommendation to remove the additional expenditure (and the AER's decision to adopt Nuttall Consulting's recommendation) is inconsistent with Nuttall Consulting's conclusion that CitiPower is relatively efficient.[616]

Regardless, CitiPower maintains that the additional expenditure associated with these projects is prudent and efficient and consistent. As outlined in more detail in Annexure 9.1:

- As was foreshowed by SKM at the time, the two areas where SKM's estimates were prone to inaccuracy were in respect of cable routes and building refurbishment costs.[617]
- The final cable routes varied from the initial estimates as a result of detailed design and feasibility studies. A market tender process has just been completed, which indicates that the forecasts included in the Revised Regulatory Proposal **underestimate** the costs for the cable installation.
- Due to the difficulties with the civil arrangements around installing the new 66kV GIS switchgear at VM (Victoria Market) in the existing 66kV switching bay, CitiPower engaged Maunsell (the consultant that advised the ESCV for the purposes of its final

[613] AER, Draft Determination, p335.
[614] Included in Attachment 161 to this Revised Regulatory Proposal.
[615] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p99.
[616] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p21.
[617] SKM, Review of CBD Security of Supply and Planning Standards, 22 August 2006 (annexed to CitiPower's Melbourne CBD Security of Supply Enhancement Project, Submission to the Essential Services Commission), 11 September 2006 (Attachment 255 to this Revised Regulatory Proposal), p40.

decision in respect of the CBD Security of Supply project) to recommend the best solution for the VM zone substation. The lowest cost option was higher than the regulatory test value by $3.88M ($2010).[618]

- A structural report of W (Waratah Place), the long-term plans to convert W into a zone substation outside of this regulatory period and firm quotes for the station work at BQ (Bouverie-Queen) and VM, indicate that costs have increased.
- A market tender process for the refurbishment costs for the BQ zone substation demonstrates that the actual costs for the refurbishment, including an allowance to raise the roof, are higher than originally estimated.

Accordingly, the AER should be satisfied that the proposed capex on these projects set out in the Initial Regulatory Proposal (and maintained in this Revised Regulatory Proposal) is prudent and efficient.

Other reinforcement projects proposed by CitiPower

The AER also accepted Nuttall Consulting's assessment that there was a low probability (39 per cent) of CitiPower's reinforcement capex (other than the capex relating to the CBD Security of Supply and Metro 2012 projects) being required as proposed in the next regulatory control period.[619] However, Nuttall Consulting's methodology for determining this probability is flawed.

To reach its overall conclusion on the probability of all projects other than the CBD Security of Supply and Metro 2012 projects being required as proposed in the next regulatory control period, Nuttall Consulting:[620]

- assigned to four proposed projects a probability of those projects being required. Nuttall Consulting assigned a probability (of either low – 33 per cent, moderate – 50 per cent, moderate/high – 70 per cent or high – 90 per cent) based on:
  - its assessment of the individual project; and
  - its 'broader findings' from the methodology review and expenditure analysis; and
- then extrapolated the weighted average probability of these four projects being required across the remainder of the proposed reinforcement capex (excluding the CBD Security of Supply and Metro 2012 projects).

The errors in Nuttall Consulting's probability assessment are four fold. First, Nuttall Consulting's assessment of the four individual projects assessed is heavily reliant on Nuttall Consulting's engineering judgment and is flawed. As shown in Table 9.5 below, the three projects assessed by Nuttall Consulting, which are maintained in this Revised Regulatory Proposal, will be required as proposed in the next regulatory control period.

Second, while Nuttall Consulting has accounted for projects that will be deferred, and has noted the possibility of projects being advanced,[621] Nuttall Consulting does not take into

[618] Maunsell, VM Substation Options Report, 31 March 2009 (Attachment 256 to this Revised Regulatory Proposal); Metro 2012; CBD Security of Supply quote tables, 8 July 2010 (Attachment 257 to this Revised Regulatory Proposal).
[619] AER, Draft Determination, p322.
[620] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p55.
[621] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p95.

account the possibility that projects that are not currently reflected in CitiPower's forecasts may be brought forward to fall within the regulatory control period.

Third, Nuttall Consulting's 'broader findings' do not justify a reduction in the assigned probabilities. This is because:

- in forecasting its reinforcement capex, CitiPower has:
    - applied the same criteria as are set out in its governance documents, and applied these criteria with the same rigour as it does during its governance processes (which Nuttall Consulting has concluded are likely to result in efficient and prudent outcomes[622]); and
    - taken into account potential synergies and produced forecasts that are economically justified;
- Nuttall Consulting's criticisms of CitiPower's load profile and transformer outage duration assumptions are not justified. Further, overall, SKM found that CitiPower's approach to energy at risk modelling is likely to **understate** energy at risk;[623]
- the maximum demand forecasts used by CitiPower in preparing its reinforcement capex forecasts are likely to result in reinforcement capex forecasts that reasonably reflect the capex criteria; and
- CitiPower has not taken into account factors other than energy at risk (and potential synergies) and high and low voltage network utilisation and compliance in forecasting reinforcement capex.

Finally, it is not reasonable to extrapolate the probabilities for four major projects across CitiPower's reinforcement capex (other than CBD Security of Supply and Metro 2012 projects). These projects make up only 37 per cent of CitiPower's proposed reinforcement capex (excluding the CBD Security of Supply and Metro 2012 projects).

As discussed above, subsequent to the submission of the Initial Regulatory Proposal, CitiPower identified that one of the material projects reviewed by Nuttall Consulting will not go ahead in the next regulatory control period. Specifically, the third transformer at SB zone substation has been deferred beyond the current regulatory control period and is thus not included in this Revised Regulatory Proposal. However, CitiPower maintains that the remaining projects reviewed by Nuttall Consulting will be required as proposed in the next regulatory control period. The reasons for this are outlined in Table 9.5 below.

Project reviewed	Nuttall Consulting assessment	CitiPower response
11kV feeder works	Half the works appear to be security related and the other half are capacity related. The ESCV's Security of Supply Decision project indicates that 11kV feeder works are required to realise the full improvements in security levels referable to the CBD Security of Supply project but	Included in Attachment 161 to this Revised Regulatory Proposal is a network planning proposal that provides more detailed information on the economic analyses performed in forecasting the 11kV feeder works in the next regulatory control period. The attached network planning proposal identifies the projects that are security related, and which are

[622] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p297.
[623] SKM, SKM Comments on Nuttall Consulting Report RE: impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p21.

Project reviewed	Nuttall Consulting assessment	CitiPower response
	revisions to the Distribution Code mean that it is unclear as to what flexibility CitiPower has in altering the CBD Security of Supply project.[624] The costs for these works were not included in the regulatory test submitted to the ESCV and the inclusion of the works may result in material deferment of the overall project.[625] CitiPower has not demonstrated that the security related 11kV feeder elements are all required.[626] Regarding the capacity related works, the energy at risk does not support the works and there may be other lower cost options (for example, advancement of the development of the existing W switching station into a 66/11kV zone substation).[627] Low probability of being required as proposed (33%).[628]	capacity related.[629] Security works In the ESCV's Security of Supply Decision, the ESCV noted the importance of CitiPower's 11kV distribution network to achieving N-1 secure.[630] The ESCV's Security of Supply Decision required CitiPower to '*certify, upon completion of the project, that N-1 Secure has been delivered to the Melbourne CBD at the 66kV sub-transmission level.*'[631] The ESCV specified, in Appendix B.1.8 to the ESCV's Security of Supply Decision, particular feeder works that it expected would be completed at the same time as the security works to ensure the objective of moving from N-1 to N-1 secure in the Melbourne CBD area.[632] This included 11kV feeder works to ensure N-1 Secure at the WA, LQ and MP zone substations. As noted by CitiPower at the time of the ESCV's Security of Supply Decision, however, 11kV transfer capability is most efficiently built in conjunction with on-going load growth related augmentations.[633] Since the time of the ESCV's Security of Supply Decision, CitiPower has reviewed the load at risk at each CBD zone substation and has proposed a more efficient alternative proposal to the works listed in Appendix B.1.8 of the ESCV's Security of Supply Decision.[634] The 11kV feeder projects proposed meet the same objectives as discussed in the ESCV's Security of Supply Decision, i.e. to transfer load to the BQ zone substation.[635] Nuttall Consulting has not identified which provision of the Distribution Code it considers is unclear as to the flexibility CitiPower has in altering its *Melbourne CBD Security of Supply Project Plan*. As shown in the network planning proposal, the security related

[624] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p97.
[625] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p97.
[626] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p97.
[627] AER, Draft Determination, p321.
[628] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p97.
[629] CitiPower, Network Planning Proposal, 11kV Feeder Works for CBD v1.1 (included in Attachment 161 to this Revised Regulatory Proposal), p4.
[630] ESCV's Security of Supply Decision (Attachment C0192 to the Initial Regulatory Proposal), p14.
[631] ESCV's Security of Supply Decision (Attachment C0192 to the Initial Regulatory Proposal), pvi.
[632] ESCV's Security of Supply Decision (Attachment C0192 to the Initial Regulatory Proposal), p15.
[633] ESCV's Security of Supply Decision (Attachment C0192 to the Initial Regulatory Proposal), p14.
[634] CitiPower, Network Planning Proposal, 11kV Feeder Works for CBD v1.1 (included in Attachment 161 to this Revised Regulatory Proposal).
[635] ESCV's Security of Supply Decision (Attachment C0192 to the Initial Regulatory Proposal), p13.

Project reviewed	Nuttall Consulting assessment	CitiPower response
		11kV feeder works are required in the next regulatory control period.[636] CitiPower rejects Nuttall Consulting's assertion that the proposed feeders works *'may result in a material deferment of the overall project, in terms of when the project maximises the net benefits'*.[637] CitiPower is proposing the works to ensure compliance with its *Melbourne CBD Security of Supply Project Plan.* <u>Capacity works</u> The attached network planning proposal demonstrates that the energy at risk justifies the 11kV feeder works that are related to capacity and that there are no lower cost alternatives.[638] Accordingly, the project should be assigned 100% probability of being required as proposed.
3rd transformer at BQ (Bouverie-Queen) zone substation	The primary need for the project is the load transfers to BQ that will result from the 11kV feeder transfers above.[639] Given the low probability that the 11kV feeder works will be required next period, there is an equally low probability that the third transformer will be required at BQ.[640] The cost of energy at risk does not appear to justify the project and other alternative options have not been sufficiently considered (for example, the advancement of the W switching station conversion).[641] Low probability of being required as proposed (33%).[642]	For the reasons outlined above, the 11kV feeder works will be required in the next regulatory control period. Accordingly, the third transformer will be required at BQ. Considering the sensitivity analysis around the 11kV feeder transfers and the new load growth in surrounding area, the energy at risk will justify the third transformer. Included in Attachment 161 to this Revised Regulatory Proposal is a network planning proposal that shows that the expected cost of the energy at risk justifies the projects and provides more detailed information on the economic analyses in respect of this project. CitiPower notes that converting the W switching station would involve similar costs to establishing BQ. However, as noted in the attached network planning proposal, there would be additional costs associate with distribution transfers to W (including because W is further away from the former Carlton and United Breweries site). The project should be assigned 100% probability of being required as proposed.

[636] CitiPower, Network Planning Proposal, 11kV Feeder Works for CBD v1.1 (included in Attachment 161 to this Revised Regulatory Proposal).
[637] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p97.
[638] CitiPower, Network Planning Proposal, 11kV Feeder Works for CBD v1.1 (included in Attachment 161 to this Revised Regulatory Proposal).
[639] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p98.
[640] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p98.
[641] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p98; AER, Draft Determination, p321.
[642] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p98; AER, Draft Determination, p321.

Project reviewed	Nuttall Consulting assessment	CitiPower response
DA (Docklands area) zone substation upgrade	The key driver for this project is the projected loading at the existing substation.[643] CitiPower's analysis only marginally supports the timing of this project. Given the load profile assumed by CitiPower is from 2001-05 and is likely to be flatter than is reasonable, this project may well be optimally deferred.[644] Further, the cost estimates are not a reasonable estimate of the efficient costs for the project and lower cost options have not been considered (for example, establishment of a second 66/11kV zone substation in the DA supplied from Fishermans Bend terminal station).[645] Moderate probability of being required as proposed (50%).[646]	Included in Attachment 161 to this Revised Regulatory Proposal is a material projects template for this project that provides more detailed information on the economic analyses performed in forecasting this expenditure. The template justifies the proposed timing of this project. In any event, Nuttall Consulting accepted the forecast timing of this project was reasonable and raised concerns only in respect of CitiPower's load profile assumptions. As discussed above, CitiPower's load profile assumptions are reasonable and will not overstate the energy at risk. The probability of the project being required cannot therefore be reduced on the basis of these. CitiPower maintains that its proposed costs are reasonable and that the proposed alternative is the lowest cost option. In respect of the suggested lower cost option proposed by Nuttall Consulting (the establishment of a second zone substation in the DA), CitiPower notes that the cost of this would be significantly higher. The reasons for this include the following: • **Land:** CitiPower owns the existing DA site, but to establish a new zone substation in the DA supplied from Fisherman's Bend terminal station it would have to identify and purchase or lease a new site. • **Subtransmission:** Under its proposal, CitiPower would upgrade conductors on the existing WMTS overhead towers to the DA zone substation. To establish a new zone substation, CitiPower would have to install new 66kV feeders from the Fisherman's Bend terminal station, which is further away and would involve crossing the Yarra river. • **Distribution:** 11 kV feeders are already in place at the existing DA zone substation – the only work involved would potentially be to cutover to a new bus. By contrast, if a new zone substation was built, new 11kV feeders would have to be installed. The project should be assigned 100% probability of being required as proposed.

Table 9.5 CitiPower's response to Nuttall Consulting's individual project assessments

[643] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p99.
[644] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp95 and 99.
[645] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p99.
[646] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p99; AER, Draft Determination, p321.

CitiPower notes Nuttall Consulting's comment that:[647]

> *'It is also worth noting that the need for the additional cable to BQ, which is also within the Metro 2012 project, has not been formally reviewed. However, given the findings presented here [in relation to the third transformer at the BQ zone substation], it may well be that this cable will not be justified at the time proposed by CitiPower.'*

As discussed in Table 9.5 above, the third transformer will be required as proposed at BQ in the next regulatory control period. Accordingly, the additional 66kV cable from BQ will also be required to ensure that CitiPower can meet its objective under the ESCV approved Melbourne CBD Security of Supply Project Plan of improving 66kV transfer capability between zone substations and terminal stations.[648] As the AER is aware, under clause 3.1A.4 of the Distribution Code, CitiPower cannot amend the Melbourne CBD Security of Supply Plan Project Plan without the approval of the ESCV if the amendment prejudices the achievement of the security of supply objectives or result in a reduction of the standard of works that are specified in that Plan.

In any event, the additional cable is required regardless of whether the third transformer is installed. The cable to BQ, as Nuttall Consulting observes, is also part of the approved regulatory test for the Metro 2012 project. The Metro 2012 project involves the installation of two BTS-BQ cables and two 55MVA transformers at BQ (part of the normal N-1 capacity planning). The CBD Security of Supply project is designed to enhance the security of supply to the CBD. This requires a third cable from BTS to meet the objectives of the approved Melbourne CBD Security of Supply Project Plan. The third cable provides enhanced security by enabling the rearrangement of the 66kV subtransmission network and is not related to transformer capacity (and hence the third transformer at BQ).

9.8.3.4 Nuttall Consulting's forecasts

For the reasons outlined above, on the basis of the material before it, the AER should be satisfied that CitiPower's proposed reinforcement capex reasonably reflects the capex criteria. In the event it is not so satisfied, however, it would not be reasonable for the AER to substitute the reinforcement capex forecasts determined by Nuttall Consulting.

Nuttall Consulting's approach to forecasting reinforcement capex is novel. CitiPower is not aware of it having been applied in any previous AER determination, or any previous determination by the ESCV. As a result, it is an untested approach to forecasting reinforcement capex.

Perhaps because of this Nuttall Consulting's forecasting methodology and the assumptions underpinning its approach are flawed. The methodology is flawed because:

- the forecasts are not linked to maximum demand forecasts. Aside from noting that the AER's conclusions on maximum demand forecasts support its view that many of the

[647] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p101; AER, Draft Determination, p98.
[648] CitiPower, Melbourne CBD Security of Supply Project Plan (Attachment 252 to this Revised Regulatory Proposal), 16 June 2008, p4; ESCV, letter from ESCV approving security of supply upgrade plan, 18 August 2008 (Attachment 253 to this Revised Regulatory Proposal).

projects included in CitiPower's forecasts of reinforcement capex may be optimally deferred, Nuttall Consulting does not consider maximum demand. In particular, Nuttall Consulting's forecasts of reinforcement capex do not reflect any explicit consideration of maximum demand. This is inconsistent with the AER's recognition that the primary driver of reinforcement capex is '*to meet the growing demand on the network*' and '*to ensure [network components] have sufficient capacity to meet high peak demand days*'[649] (so as to avoid asset utilisation rates exceeding the upper bounds of good engineering practice);

- Nuttall Consulting's determination of the probability of the reinforcement capex projects going ahead is not reasonable. This is because:
  - Nuttall Consulting's assessment of each of the projects included in this Revised Regulatory Proposal is heavily reliant on engineering judgement and is incorrect. For the reasons set out in Table 9.5 above, these projects have a 100 per cent probability of being required as proposed in the next regulatory control period; and
  - as discussed above, Nuttall Consulting's 'broader findings' regarding CitiPower's forecasting methodology do not justify a reduction in the probabilities assigned to individual projects.

  In addition, as noted above, while Nuttall Consulting has accounted for projects that will be deferred, and has noted the possibility of projects being advanced, Nuttall Consulting does not take into account the possibility that projects that are not currently reflected in the CitiPower's forecasts may be brought forward to fall within the regulatory control period;
- it is not reasonable to extrapolate the probabilities for four major projects across CitiPower's reinforcement capex (other than the CBD Security of Supply and Metro 2012 projects); and
- as discussed in more detail above, the additional expenditure forecast for the CBD Security of Supply and Metro 2012 projects is efficient and prudent.

9.8.4 CitiPower's Revised Regulatory Proposals

The reinforcement forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 9.6 below.

	$'000 (real 2010)					
Expenditure category	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
Reinforcements	60,673	66,586	81,668	66,181	47,378	**322,486**

Table 9.6 Reinforcement capex forecasts included in the Revised Regulatory Proposal

9.9 Reliability and quality maintained capex

9.9.1 CitiPower's Initial Regulatory Proposal

Reliability and quality maintained capex is required to maintain network performance within acceptable risk levels, as well as to replace assets that have failed or are imminently

649 AER, Draft Determination, pp311-2.

about to fail. Reliability and quality maintained capex is necessary because with time, network assets age and deteriorate and, if they are not replaced, may fail or operate at a sub-standard level. This may result in reduced service reliability and quality.

Subsequent to the Initial Regulatory Proposal, CitiPower provided to the AER material program templates for each activity within each reliability and quality maintained capex function code.[650] These templates provided details in respect of the historic and forecast expenditure for that activity, where there was reliable historic expenditure at the program level. CitiPower highlighted that historical expenditure is generally not maintained at the program level, rather, it is maintained at the aggregate function code level.

Some of the more significant replacement programs proposed by CitiPower in its Initial Regulatory Proposal for the next regulatory control period are discussed in more detail below.

9.9.1.1 Fault mitigation program

In its Initial Regulatory Proposal, CitiPower proposed capex for a program to mitigate anticipated increases in fault levels on the network. As noted by CitiPower in its Initial Regulatory Proposal:[651]

- Key equipment installed on the distribution system is designed with a maximum fault limit. Exceeding the equipment's limit will increase the risk to the reliability and safety of the distribution system.
- Maintaining fault levels at or below plant and equipment limits has become increasingly challenging for CitiPower due to government policies that seek to encourage greater investment in embedded generation. This is because:
  - In contrast to the traditional flow of electricity from the transmission network to the end customer via the distribution system, embedded generation (or distributed generation) requires electricity to flow in both directions: to the end customer for consumption when the customer's generation capacity is insufficient to meet its electricity needs; and back into the network when the customer is generating excess capacity.
  - Embedded generation therefore contributes to the fault level energy that will flow into the local network when a localised network fault occurs.
- Accordingly, CitiPower anticipates increased faults in the next regulatory control period and proposed additional capex for maintaining fault levels within safe limits that are consistent with the provision of a reliable and secure supply of electricity to its customers.

In 2008, CitiPower decided to manage the growth in fault levels in the short term by segmenting the network to increase impedance. That is, CitiPower adopted a strategy of opening selected 11kV bus tie circuit breakers at the zone substation level to allow fault levels to drop. However, CitiPower recognises this can potentially undermine the security of the network and increase supply interruptions and thus may not be the optimal means of

[650] Material program templates were provided to the AER by email on 26 February 2010 and 3 March 2010.
[651] Initial Regulatory Proposal, pp107-9.

managing fault levels in the longer term. This view appears to have been shared by the ESCV.[652]

The program proposed by CitiPower in the next regulatory control was intended to replace its short term strategy of opening zone substation circuit breakers. It was based on the recommendations of an independent expert, SKM.[653] The nature of the investment was discussed in detail in a further report by SKM, which was attached to the Initial Regulatory Proposal.[654]

9.9.1.2 Zone substation secondary replacements

Secondary equipment has an important role to ensure that the reliability of the network is always at its optimal condition. In its Initial Regulatory Proposal, CitiPower proposed zone substation secondary replacements in accordance with its RCM methodology. This methodology is generally applied to routine replacement expenditure, taking into account the asset age, condition and operating environment.

Subsequent to the Initial Regulatory Proposal, CitiPower provided to the AER material program templates for all zone substation secondary replacement activity.[655]

One of the more significant programs under this category of expenditure is relay replacement.[656]

9.9.1.3 Nilsen LV air circuit breaker replacement

CitiPower's reliability and quality maintained capex forecasts included amounts for the replacement of 97 Nilsen LV air circuit breakers in the next regulatory control period.[657]

As noted in the asset management plan attached to the Initial Regulatory Proposal, the proposed program was the result of detailed investigations into the failure of two units (in 2005 and 2007).[658] Nilsen LV air circuit breakers are located in indoor distribution substations (e.g. in high rise buildings).[659] These two failures therefore resulted in evacuations of major CBD buildings (with associated emergency service costs and economic loss for businesses operating from these buildings) and, most significantly, posed a risk to the health and safety of the public and employees.[660]

In 2009, CitiPower introduced its program to replace a proportion of its Nilsen LV air circuit breakers (i.e. the particular series that failed in 2007 and 2007) to remove the

[652] ESCV, Letter to CitiPower regarding management of fault current level within CitiPower's distribution network, 17 October 2008 (Attachment 261 to this Revised Regulatory Proposal).
[653] SKM, Fault Level Mitigation Issues Paper: Embedded Generation in CitiPower Distribution System, 5 May 2009 (Attachment C0186 to the Initial Regulatory Proposal).
[654] SKM, Accommodating Distributed Generation in the CitiPower Network, 29 October 2009 (Attachment C0002 to the Initial Regulatory Proposal).
[655] Each of the material program templates under function code 156 provided to the AER by email on 26 February 2010.
[656] Document titled 'PAL Ageing_Unreliability Relay Replacement', provided to the AER by email on 26 February 2010.
[657] Document titled 'CP 143 – Nilsen' (provided to the AER by email on 3 March 2010).
[658] CitiPower and Powercor Australia, Network Asset Replacement Policy for 3000A LV air circuit breakers – type Nilsen "AB" Series, 25 November 2009 (Attachment C0108 to the Initial Regulatory Proposal), p5.
[659] CitiPower and Powercor Australia, Network Asset Replacement Policy for 3000A LV air circuit breakers – type Nilsen "AB" Series, 25 November 2009 (Attachment C0108 to the Initial Regulatory Proposal), p5.
[660] CitiPower and Powercor Australia, Network Asset Replacement Policy for 3000A LV air circuit breakers – type Nilsen "AB" Series, 25 November 2009 (Attachment C0108 to the Initial Regulatory Proposal), p5.

unacceptable risk associated with any failure in this series of circuit breakers over the next regulatory control period.[661]

9.9.1.4 Reliability replacement

Reliability replacement relates to work to address worst served customers. Subsequent to the Initial Regulatory Proposal, CitiPower provided details of its reliability replacement programs, including:[662]

- the installation of covers and guards on exposed apparatus to prevent contact by animals and birds;
- the installation of high voltage fuses on spur lines;
- the installation of covering and insulation tubing on bare HV overhead lines to reduce the risk of vegetation initiated faults;
- the deployment of additional fault indicators on CitiPower's overhead and underground HV network;
- the replacement of HV bare conductor with conductor covered with thick insulation;
- the installation of LV spreaders; and
- the installation of remote alarm and fault indication at distribution substations with restricted access.

9.9.2 AER's Draft Determination

The AER commented in its Draft Determination that, in previous regulatory proposals, DNSPs used 'black boxed proprietary' models and the AER was unable to assess the underlying assumptions within, or confirm the outputs of, these models.[663]

To assist it to assess DNSPs' reliability and maintained capital expenditure proposals, in September 2009, the AER engaged Nuttall Consulting to develop the Repex Model.[664] The Repex Model uses age as a proxy for the many factors that drive individual asset replacements.[665]

The Repex Model assumes that recent historic replacement levels are reflective of the prudent and efficient management of the asset base[666] and *'was ... calibrated so that it reflected historical levels and costs'*[667].

In its Draft Determination, the AER used the Repex Model forecasts:[668]

- as a check on the DNSPs' proposed reliability and quality maintained expenditure; and

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[661] CitiPower and Powercor Australia, Network Asset Replacement Policy for 3000A LV air circuit breakers – type Nilsen "AB" Series, 25 November 2009 (Attachment C0108 to the Initial Regulatory Proposal), p5.
[662] See templates relating to function code 166, provided to the AER on 3 March 2010.
[663] AER, Draft Determination, p339.
[664] AER, Draft Determination, p339.
[665] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p29.
[666] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p29.
[667] AER, Draft Determination, p339.
[668] AER, Draft Determination, pp338-9.

- in a number of the above categories of reliability and quality maintained expenditure, as a substitute forecast for the proposed forecast.[669]

The AER raised concerns with, and reduced on the basis of the Repex Model, the following items of reliability and quality maintained expenditure:[670]

- fault level mitigation expenditure;
- zone substation plant replacement;
- zone substation secondary systems replacement;
- HV replacement;
- services replacement;
- fuse and surge diverters and transformer replacement;
- reliability replacement; and
- fault related replacement.

The AER's reasoning behind the rejection of the proposed reliability and quality maintained capex in respect of some of the more significant of these programs is discussed below.

9.9.2.1 Fault level mitigation

The AER agreed with Nuttall Consulting's recommendation that no allowance should be allocated for CitiPower's fault level mitigation program.[671]

The AER raised concerns that:[672]

- CitiPower has not provided sufficient cost benefit analysis in respect of the program;
- the benefit from the program only accrued to those customers wanting to connect an embedded generator and thus the AER did not consider that the costs of the fault level mitigation project should be borne by all customers; and
- the reasons for the program appear to have existed in the current regulatory control period and CitiPower has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period.

9.9.2.2 Zone substation secondary systems replacement

The AER was not satisfied that the forecast expenditure for the zone substation secondary systems replacement reasonably reflects the capex criteria.[673]

The AER raised concerns in respect of the projected costs of the replacement of aged relays (which constituted 12 per cent of the reliability and quality maintained expenditure on zone substation secondary systems replacements forecast in the Initial Regulatory Proposal).[674]

[669] Zone substation plant replacement, zone substation secondary systems replacement, HV switch replacement, services replacement, fuse and surge diverters and transformer replacement and fault related replacement.
[670] AER, Draft Determination, pp346-55.
[671] AER, Draft Determination, p347.
[672] AER, Draft Determination, pp346-7.
[673] AER, Draft Determination, pp349-50.
[674] AER, Draft Determination, pp349-50; Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p113.

The AER indicated that while the volume of the relays replaced is expected to decline in the next regulatory control period, the expenditure proposed by CitiPower did not.[675]

Regarding the current and proposed programs more generally, the AER indicated that:[676]

- CitiPower has not provided sufficient cost benefit analysis in respect of the programs;
- the risks appear to have existed in the current regulatory control period and CitiPower has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period; and
- CitiPower has not adequately demonstrated how its asset management plans or engineering judgment have been reflected in the expenditure forecasts.

The AER adopted Nuttall Consulting's recommended allowance based on average expenditure over 2006-08, with an increase based on the Repex Model.[677]

9.9.2.3 Nilsen LV air circuit breaker replacement

The AER rejected CitiPower's forecast expenditure for its Nilsen LV air circuit breaker replacement program.[678]

The AER did not consider that CitiPower's proposed replacement of all 97 of its Nilsen LV circuit breakers was justified. The AER concluded that two failures of these circuit breakers (in 2005 and 2007) did not justify the proposed replacement.[679] The AER also noted that:[680]

- CitiPower has not provided sufficient cost benefit analysis in respect of the proposed programs;
- the risks appear to have existed in the current regulatory control period and CitiPower has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period; and
- CitiPower has not adequately demonstrated how its asset management plans and engineering judgment has been reflected in the expenditure forecasts.

The AER adopted Nuttall Consulting's recommended allowance based on average expenditure over 2006-08, with an increase based on the Repex Model.[681]

9.9.2.4 Reliability replacement

The AER rejected CitiPower's proposed reliability expenditure in its entirety on the basis that:[682]

- CitiPower has not provided sufficient cost benefit analysis in respect of the proposed programs;

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675 AER, Draft Determination, pp349-50.
676 AER, Draft Determination, pp349-50.
677 Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p126.
678 AER, Draft Determination, pp351-2.
679 AER, Draft Determination, p351.
680 AER, Draft Determination, p351.
681 Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p126.
682 AER, Draft Determination, p354.

- the risks appear to have existed in the current regulatory control period and CitiPower has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period; and
- CitiPower has not adequately demonstrated how its engineering judgment has been reflected in the expenditure forecasts.

The AER endorsed Nuttall Consulting's conclusion that:[683]

> *'As expenditure is not captured to this activity code prior to 2010, it is not clear how similar works have been allocated historically. However, assuming that similar works in the current period have been captured in the other RQM activity codes, we consider that there should already be some allowance for these proposed works in other activity code allowances.'*

9.9.3 CitiPower response to the AER's Draft Determination

CitiPower maintains that its reliability and quality maintained capex forecasts in the Initial Regulatory Proposal reasonably reflect the capex criteria. However, for the purposes of this Revised Regulatory Proposal, CitiPower has adopted the amounts in the AER's Draft Determination in respect of the following reliability and quality maintained programs:

- zone substation replacement;
- services replacement; and
- fuse and surge diverters and transformer replacement.[684]

CitiPower has provided in this Revised Regulatory Proposal additional details regarding key reliability and quality maintained capex programs that it maintains as originally proposed for the next regulatory control period.

CitiPower does not consider that the Repex Model is capable of forecasting reliability and quality maintained capex that reasonably reflects the capex criteria. However, even if the calibrated Repex Model is assumed to produce reasonable forecasts, the independent expert, PB, found that the Repex Model supports CitiPower's forecasts. Removing the two major drivers of the increase in CitiPower's forecast in the next regulatory control period (the fault level mitigation and reliability replacement programs), which PB considered should be evaluated as step change increases, PB concluded that the variation between the calibrated Repex Model and CitiPower's forecasts did not justify an adjustment to CitiPower's proposed forecast.

CitiPower observes, for completeness, that it is not relying on 'black box' forecasting models to forecast reliability and quality maintained capex in the current price review process and did not rely on such models in the 2006-10 price review process before the ESCV. In the 2006-10 price review process, CitiPower utilised the proprietary model used by the ORG in the ORG's 2001-05 EDPR. In the current process, rather than rely on a 'black box' model, CitiPower has used transparent, bottom-up build processes to produce

[683] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p119; AER, Draft Determination, p354.

[684] CitiPower observes that, in its Draft Determination, the AER noted the error in CitiPower's forecast of fault related expenditure in the Initial Regulatory Proposal. The AER accepted the revised forecast provided to the AER by CitiPower of $22.4 million: AER, Draft Determination, p354. CitiPower has included this revised forecast in this Revised Regulatory Proposal.

efficient and prudent reliability and quality maintained forecasts for the next regulatory control period. By contrast, CitiPower notes that the AER's Repex Model is a 'black box' proprietary model.[685]

9.9.3.1 The AER's Repex Model and its application in the Draft Determination

CitiPower has significant concerns that the Repex Model, including the way in which it was used in the Draft Determination, will not produce forecasts of reliability and quality maintained capex for 2011-15 that reasonably reflect the capex criteria.

Following the release of the AER's Draft Determination, CitiPower engaged PB to consider the AER's approach to assessing CitiPower's reliability and quality maintained capex forecasts for the next regulatory control period.[686] CitiPower also invited EA Technology to comment on the AER's Draft Determination and the underlying Nuttall Consulting report.[687]

As discussed in the 'General issues' section above, it is not appropriate for the AER to use actual data from 2006-08 to model historical expenditure. The AER should also be using actual expenditure data from 2009. Regardless, it is not appropriate to calibrate the Repex Model using historic expenditure. This equates to adopting a 'revealed cost' approach, which as noted in the 'General issues' section above, is not a reasonable basis on which to prepare forecasts of capex for 2011-15 that reasonably reflect the capex criteria. As PB concludes in respect of its review of the Repex Model:[688]

> *'...the AER's approach assumes that the asset condition and associated business risks over the period from 2006 to 2008 are not materially different to those expected over the next regulatory control period. In the absence of an ex-post review of the drivers of actual replacement expenditure, PB considers that limited conclusions can be drawn based on historical levels of expenditure, particularly over relatively short periods.'*

These concerns were shared by EA Technology.[689] Further, EA Technology observed that the Repex Model '*uses coarser granularity than the Ofgem model'* (on which it is based).[690] Specifically, *'distribution assets are broken down into 11 categories, compared with 68 asset classes used by Ofgem'*.[691]

PB also concluded that, as the Repex Model does not take account of replacement drivers other than asset age, the model is unlikely to produce reasonable forecasts of capex that reflect the circumstances of DNSPs in the next regulatory control period.[692] PB stated:[693]

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[685] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p11.
[686] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal).
[687] EA Technology, Commentary on Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15 (Draft Decision) June 2010, July 2010 (Attachment 163 to this Revised Regulatory Proposal).
[688] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pvi.
[689] EA Technology, Commentary on Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15 (Draft Decision) June 2010, July 2010 (Attachment 163 to this Revised Regulatory Proposal), p4.
[690] EA Technology, Commentary on Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15 (Draft Decision) June 2010, July 2010 (Attachment 163 to this Revised Regulatory Proposal), p4.
[691] EA Technology, Commentary on Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15 (Draft Decision) June 2010, July 2010 (Attachment 163 to this Revised Regulatory Proposal), p4.
[692] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p13.

> *'The substitute forecasts may not be sufficient to address the specific needs and risks identified in the businesses' submitted AMPs, reflecting the assessed asset condition. Given that these needs include factors other than age, it is not clear how the Repex model is able to estimate the risks associated with replacement drivers that are not related to time based deterioration (e.g. technical obsolescence, changes in statutory obligations, parts availability, etc.) or do not fit the assumed failure profile (such as multi-modal failure profiles due to differing root causes).'*

In addition to raising specific concerns with the Repex Model itself, PB raised concerns with three aspects of the approach taken to the review by Nuttall Consulting and the AER.[694] These were:

- the reasons for rejecting the DNSPs' proposals;
- the determination of substitute forecasts; and
- an inconsistent application of the Repex Model findings.

Each of these matters is discussed in turn below.

Regarding the reasons for rejecting the DNSPs' proposals, PB summarised that DNSP proposals were rejected on the basis of benchmarking analysis, and a high level assessment of the historical variation between the regulatory allowance and the actual expenditure over the previous and current regulatory control periods.[695]

PB observed that it was unusual that, in circumstances where Nuttall Consulting accepted that the plans proposed by the DNSPs' were generally reasonable and '*at an internal level to identify likely future network needs, work levels and associated expenditure*', Nuttall Consulting formed the view that these plans were not suitable for preparing regulatory forecasts.[696]

PB noted that without a fundamental assessment of the needs and risks advanced in the asset management plans and the forecasting approach taken by the DNSPs, and in the absence of any third party review of the Repex Model, a misalignment between results from the Repex Model and the models used by the DNSPs does not necessarily demonstrate that the higher value is unreasonable, imprudent or inefficient.[697] PB concluded that:[698]

> *'On the basis that there appears to have been little analysis of the fundamental needs set out in the documentation supporting the businesses' expenditure proposals, and that the accuracy of the Repex model has neither been verified by a third party or demonstrated through calibration at a detailed level, PB considers that Nuttall's dismissal of the expenditure proposal due, in a large part, to non-alignment with the Repex model results does not reflect the specific risks faced by the business over the next regulatory control period, and does not reflect a reasonable benchmark for the acceptance/rejection of the businesses proposal.'*

[693] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p13.
[694] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp10-6.
[695] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p10.
[696] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p10-1.
[697] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p11.
[698] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p12.

In respect of the AER's use of the Repex Model to determine substitute forecasts, PB raised concerns that the AER's approach did not comply with the Rules.[699] Specifically, PB considered that:[700]

- the substitute forecast was not based on the regulatory proposal, but rather was based on the independently developed Repex Model results; and
- no attempt has been made to demonstrate that the Repex Model adjusts forecasts only to the minimum extent necessary to achieve the capex objectives or that the substitute forecast is sufficient to meet the expenditure needs of the business over the next regulatory control period. Rather, Nuttall Consulting has proposed that the DNSPs should *'demonstrate why they cannot manage the overall risks within the overall recommendations'*.

Finally, PB observed that, to determine whether a DNSP's forecast is accepted or not, Nuttall Consulting has generally:[701]

- adopted a DNSP's proposal at the activity code level where the proposed forecast is close to or lower than the Repex Model or consistent with the 2006-08 average expenditure; and
- adopted the Repex Model forecast at the activity code level in cases where the DNSP's forecast is above the Repex Model.

PB raised three concerns with this approach by Nuttall Consulting to using the results of the Repex Model.

First, PB noted its understanding that, given the limited calibration of the Repex Model at a detailed level, the Repex Model is intended to produce a reasonable estimate of the future replacement requirements only at the total expenditure level.[702] Therefore, PB concluded that *'using Repex model forecasts at the activity code level as an acceptance/rejection criterion is inappropriate'*.[703] PB considered that the wide variation (-87 per cent to +401 per cent) in the accepted and rejected forecasts across the reliability and quality maintained categories '*appears to be demonstrative of the limited confidence that can be placed in the Repex model forecasts at this level*'.[704] PB further noted that Nuttall Consulting made no attempt to compare the proposed reliability and quality maintained expenditure with the total expenditure calculated by the Repex Model.[705]

Second, PB noted that *'considerable discretion has been exercised with regard to selection of a substitute forecast based on the 2006-2008 average, the Repex model results, or the business' forecast'*.[706]

Third, PB highlighted that Nuttall Consulting's inconsistent application of the substitute forecasts determined through the Repex Model gives rise to a systematic underestimation of the total substitute forecasts of reliability and quality maintained capex.[707]

[699] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp12-3.
[700] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp12-3.
[701] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p9. PB noted that there were instances where the stated approach was not applied consistently: PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp14-5.
[702] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p13.
[703] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), piii.
[704] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p18.
[705] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p14.
[706] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), piii.
[707] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p14.

Nuttall Consulting's approach of accepting the DNSP's forecast at the activity level where they are below the Repex Model forecast at the activity level and substituting the Repex Model forecast where the DNSP's forecast is higher produces a substitute for the total replacement forecast that is materially below both the forecasts proposed by CitiPower and the total replacement forecast predicted by the calibrated Repex Model. This is shown in Table 9.7 below.

Activity Code	Nuttall Consulting View	CitiPower Proposed	Calibrated Repex Model	Nuttall Recommended
Cross Arm	Accepted	12.8	12.8	12.8
Fault Level Mitigation Project	Rejected – no allowance	100.5	-	-
Fault Related	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	22.4 [39]	58.7	58.7
HV Fuse Unit & Surge Diverter	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	1.6	0.4	0.4
HV Switch	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	21.0	5.5	5.5
OH/UG Line	Accepted	30.1	44.3	30.1
Pole	Accepted	14.0	13.0	14.0
Reliability Improvement	Rejected – no allowance	5.9	-	-
Services	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	11.0	4.2	4.2
Transformer	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	2.6	2.1	2.1
Zone Substation Plant	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	90.2	83.8	83.8
Zone Substation Secondary Systems	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	40.7	5.1	5.1
Total		**352.8**	**229.9**	**216.7**
	Rejected categories (no allowances)	**(106.4)**	**-**	**-**
Total	**(ex rejected categories)**	**246.4**	**229.9**	**216.7**

Source: Nuttall Report p. 126 & PB Analysis of AER Repex CitiPower.xls

Table 9.7 PB summary of results ($m 2010)[708]

PB considered that, for the Repex Model to be considered a reasonable and unbiased estimator of the prudent and efficient replacement capex required by the DNSPs, both the total Repex Model forecast and the aggregate of the substitute forecasts should be closely aligned. PB further considered that the misalignment in the Repex Model total forecast and the aggregate of the substitute forecasts identified in Table 9.7 above could be due to:[709]

- an inherent bias in the analysis approach leading to an underestimate of the prudent and efficient level of reliability and quality maintained capex required by the DNSP;

[708] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp16-7.
[709] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p15.

- calibration errors in the Repex Model, meaning that the Repex Model does not represent a prudent and efficient substitute forecast, at least at an activity code level; and
- assumptions or simplifications in the replacement algorithms, categorisation or input data leading to unrealistic forecasts in some categories. In this case, PB noted that it is difficult to understand how the integrity and calibration of the Repex Model remains valid.

PB also noted that Nuttall Consulting's framework analysis:[710]

> '*places the risk of inaccuracy of the Repex model and the validity of its calibration on the businesses. Given that a $691m reduction across the five businesses has been recommended by Nuttall on the basis of this approach, the accuracy of the Repex model represents a material risk to the Victorian business' ability to maintain reliability and quality of supply.'*

PB concluded, therefore, that the Repex Model category forecasts should only be considered where the total replacement capex proposed by the DNSP is inconsistent with the model's total replacement capex forecast and where it can be transparently demonstrated that the activity code forecast is well calibrated to the DNSPs' asset base.[711]

In any event, even if the calibrated Repex Model is assumed to produce reasonable forecasts for the next regulatory control period, CitiPower observes that PB found that the Repex Model supports CitiPower's forecasts (excluding its step change fault level mitigation and reliability replacement programs).

After removing the step change fault level mitigation program and reclassified reliability replacement program, PB found that CitiPower's proposed capex was only 7 per cent higher than the total expenditure forecast by the calibrated Repex Model.[712] PB stated:[713]

> '*In PB's opinion, a 7% variation between a 'top down' forecast modelled on asset age and a 'bottom-up' forecast based on asset condition, risk and obsolescence issues as identified in CP's AMPs is within the range of reasonable modelling expectations.'*

Given that the Repex Model forecast is not materially different to the total forecast proposed by CitiPower, it was not clear to PB why the 'top-down' Repex Model forecast is adopted as a reasonable base over CitiPower's 'bottom-up' proposal.[714] Accordingly, PB concluded that, on the assumption that the Repex Model is a reasonable and unbiased estimate of CitiPower's future total replacement capex:

- the submitted proposal, excluding the fault level mitigation and reliability replacement programs, should be accepted as a reasonable baseline forecast of the replacement capex needs of CitiPower and no further reliance on the Repex Model is required; and
- consistent with the intent of Nuttall Consulting's methodology, the two excluded programs (i.e. fault level mitigation and reliability replacement) should be evaluated as step change increases on the basis of the fundamental need, risks and the consideration of alternative options.[715]

[710] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p14.
[711] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p15.
[712] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p17.
[713] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p17.
[714] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p17.
[715] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp17-8.

CitiPower submits that the AER need not rely on the Repex Model as its proposed reliability and quality maintained capex reasonably reflects the capex criteria. As discussed in greater detail below, the risks CitiPower anticipates will arise in the next regulatory control period justify the proposed capex.

In any event, as noted by PB, if the two major drivers of the increase in CitiPower's forecasts for the next regulatory control period are removed from the analysis and assessed as step change increases on the basis of the fundamental need, risks and the consideration of alternative options, then CitiPower's proposed capex is only around seven per cent higher than the total forecast resulting from Nuttall Consulting's calibrated Repex Model.[716] Thus, if it is assumed that the Repex Model is a reasonable unbiased estimate of CitiPower's future total replacement expenditure, CitiPower's forecast excluding these step changes can be considered a reasonable forecast of the replacement needs of the business in the next regulatory control period.[717]

9.9.3.2 Impact of the AER's Draft Determination on opex

If the AER reduces CitiPower's forecast reliability and quality maintained capex as proposed in the Draft Determination, the AER should allow additional opex to ensure that CitiPower is able to meet the NEO.

CitiPower engaged the independent expert, SKM, to conduct a study of the expected magnitude of the opex increase due to the expected ageing of the network over the period 2011-15.[718]

SKM modelled a range of scenarios, assuming:[719]

- the capex in CitiPower's Initial Regulatory Proposal was allowed;
- reductions in capex from CitiPower's Initial Regulatory Proposal equal to 10 per cent, 20 per cent, 30 per cent, 40 per cent and 50 per cent; and
- a reduction in capex consistent with the AER's Draft Determination.

Under each scenario, SKM indicated there would be an increase in age-related opex in the next regulatory control period.[720] For instance, SKM found that, if CitiPower was allowed the capex amounts in the AER's Draft Determination, the incremental increase in ageing of the network would require additional opex of $1.86m over 2011-15.[721]

Adopting a conservative approach, however, CitiPower has not included an increase in opex in this Revised Regulatory Proposal to reflect an expected increase in age-related opex in the next regulatory control period.

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[716] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p17.
[717] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p18.
[718] SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal).
[719] SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), pp17-23.
[720] SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p4.
[721] SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p23.

9.9.3.3 CitiPower's proposed reliability and quality maintained programs

CitiPower has provided in the remainder of this section of the Revised Regulatory Proposal additional details regarding key reliability and quality maintained capex programs that it maintains as originally proposed for the next regulatory control period.

Fault level mitigation

In its review of the AER's Draft Determination regarding reliability and quality maintained capex, PB concluded that it would be appropriate to allow a component of the proposed fault level mitigation capex that represents the proportion of the project that is reasonably likely to be justified over the next regulatory control period, and a weighted component to represent the proportion of the project where the efficiency of the option or the timing of its implementation is uncertain.[722]

Nonetheless, subject to receiving a statement of intent from the AER that it does not consider CitiPower's current approach to fault level mitigation breaches the Distribution Code, CitiPower does not maintain its proposed capex relating to the new fault level mitigation program included in the Initial Regulatory Proposal. CitiPower wishes, however, to:

- highlight the consequences for customers should the AER affirm its Draft Determination in the Final Determination; and
- propose reliability and quality maintained expenditure that will be required by CitiPower in the next regulatory control period if the strategy of opening 11kV bus ties at the zone substation level is continued over the next regulatory control period.

While CitiPower originally engaged in the strategy of opening zone substation circuit breakers to reduce fault levels as a temporary and prudent measure to ensure plant and equipment is operated within their fault level ratings, and to allow it to consider viable longer term options to accommodate the growing demand for connection of embedded generators, the AER's Draft Determination indicates that the AER does not consider that CitiPower continuing to engage in this strategy would be inconsistent with what constitutes 'good asset management' for the purposes of clause 3.1 of the Distribution Code. CitiPower notes that this represents a departure from the concerns raised by the ESCV in October 2008.[723]

CitiPower observes that, while the strategy of opening zone substation circuit breakers has had the desired effect of reducing fault levels, it has also had the negative effect of reducing the security, reliability and quality of supply of electricity to customers. Specifically, where the approach of opening zone substation circuit breakers is adopted, a momentary loss of supply to customers is expected for a fault on one of the transformers or cables supplying the zone substation.

In its report Fault level Mitigation Issues Paper: Embedded Generation in CitiPower Distribution System, SKM stated that CitiPower's short term strategy '*may expose*

[722] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p189.
[723] ESCV, Letter to CitiPower regarding management of fault current level within CitiPower's distribution network, 17 October 2008 (Attachment 261 to this Revised Regulatory Proposal).

customers to reduced supply quality'.[724] SKM recommended a longer term strategy to ensure customers do not experience reduced supply quality.[725]

CitiPower notes that its operational experience since 2008 confirms there will be adverse consequences to customers as a result of the short term strategy to open selected bus tie circuit breakers to reduce fault levels going forward. Specifically, CitiPower has experienced increased complaints from customers due to voltage variations in the supply from zone substations where the circuit breakers have been opened. For example, CitiPower received a customer complaint (confidential) regarding the voltage level supplied from the FR zone substation in April 2009.[726] [redacted]

The variation in voltage is caused by:

- inadequate bus voltage regulation of the newly segregated buses; and
- voltage disturbance induced through capacitor bank switching. A weaker system is created by opening bus tie circuit breakers which makes them prone to induced voltage disturbances experienced when a capacitor bank switches on and off.

If CitiPower continues the strategy of opening zone substation circuit breakers in the next regulatory control period, its required capex for doing this will increase. This is because:

- CitiPower will be required to manage the consequences of operating its network in the manner contemplated by the AER. In the absence of the program proposed in the Initial Regulatory Proposal, the opening of circuit breakers is expected to be required (to maintain fault levels within plant ratings) in the next regulatory control period at an additional:
  - 11 zone substations, due to the forecast increase in load; and
  - five zone substations, due to connection of embedded generators.

  This is an increase from four zone substations in the current regulatory control period;[728] and
- CitiPower will require an additional capex allowance for connecting embedded generators to the network.

The consequences of CitiPower continuing to operate its network by managing fault levels through the opening of zone substation circuit breakers are outlined in Table 9.8 below. The activities that CitiPower will be required to undertake in the next control period to manage these consequences are also set out.

[724] SKM, Fault level Mitigation Issues Paper: Embedded Generation in CitiPower Distribution System, May 2009 (Attachment C0186 to the Initial Regulatory Proposal), p38.
[725] SKM, Fault level Mitigation Issues Paper: Embedded Generation in CitiPower Distribution System, May 2009 (Attachment C0186 to the Initial Regulatory Proposal), p39.
[726] Attachment 262 to this Revised Regulatory Proposal.
[727] Attachment 263 to this Revised Regulatory Proposal.
[728] CitiPower is currently operating with open bus ties at the CL, RP, SO and TK zone substations. CitiPower expects it will be required to operate with a single bus tie open in the following zone substations: E, J (CBD), LS, SK, VM (CBD), WA (CBD), FB, FR (CBD), MG, MP (CBD), JA (CBD), BC (with third transformer) and WB. CitiPower expects it will be required to operate with two bus ties open in LQ (CBD) and NR. The terms of reference for the City of Melbourne 1200 Buildings Project (Attachment 260 to this Revised Regulatory Proposal) include the installation of 426 MW of embedded generation capacity (p2).

Incident	Consequences	Activity to respond to event/consequence
Voltage disturbances	Capacitor bank modules are sized to suit the fault level at the zone substation with bus ties closed. Segregating the buses means that these modules create voltage disturbances outside the Distribution Code on the weaker bus during switching. The impact to customers of this can include sensitive digital devices dropping out, uninterruptable power supplies being activated and intolerable flicker of building lighting.	Capacitor bank module reduction Voltage disturbances can be addressed by reducing the size of the capacitor bank modules to reduce the voltage variation when carrying out regular capacitor bank switching. This will reduce zone substation capacity by up to 10 per cent, and increase the energy at risk estimates at each station. The reduction of the capacitor bank size cannot be compensated by adding new modules to adjacent buses due to the space constraints with the zone substation.
Transformer load imbalance between separated buses	Transformer load imbalance (when highly loaded, e.g. greater than 20 per cent) can accelerate transform er ageing, especially the ageing of segregated single transformers. This results in higher maintenance costs due to the inefficient utilisation of assets.	Loading balance Balancing of bus load can be achieved through feeder rearrangements. At present, one zone substation (BC) has buses with a load imbalance of greater than 20 per cent.
Reduced security of supply for customers supplied radially from single a transformer	Supply will be lost to customers due to a fault on segregated single transformers or subtransmission lines supplying these transformers.	Auto close scheme Auto close schemes automatically close open bus tie circuit breakers, reducing outages to a few seconds. CitiPower will be required to extend its autoclose implementation program.
Uncontrolled transformer voltage of separated buses	Currently only one voltage regulating relay (which controls the voltage on the bus) is applied per station. With segregated buses, only one bus can be adequately controlled and the other is left uncontrolled. The uncontrolled bus can experience voltage levels outside of clause 4.2 of the Distribution Code. Uncontrolled voltage can lead to customer equipment failure or malfunction.	Voltage control CitiPower will need to install separate bus voltage regulating relays at 13 zone substations to maintain the voltage levels in accordance with clause 4.2 of the Distribution Code.
11kV paralleling across open bus ties	There will be an increase in activity in paralleling of feeders supplied from different bus voltages. This is required, as part of normal operating procedures, to suppress feeder protection at one end to avoid possible loss of feeder due to circulating currents. This will result in additional time being taken to restore supply while suppressing feeder protection.	Remote control inhibit of feeder protection CitiPower will need to install remote control inhibit on feeder protection at zone substations. This will reduce the additional time taken to restore electricity supply.
Short duration transformer overload of zone	Where there is very low impedance at a zone substation, it will require two open bus tie circuit breakers to mitigate fault level issues. Where	Remote control load transfer Remote control load transfer allows for immediate load transfer to avoid damage to plant

substations with two open bus tie circuit breakers	this is the case, a fault on a transformer will overload the transformer that will be required to supply the load on two buses. Unless there is immediate load transfer, plant damage will result to the overloaded transformer. Should an overload lead to a zone substation outage, this will result in a degradation in security of supply to customers from that substation.	and equipment. CitiPower will require load transfers to adjacent zone substations to occur by remote control at two zone substations that do not currently have this capability.
Monitoring of supply quality	With the segregation of buses, the zone substation buses would not be tied to the same voltage level. Accordingly, CitiPower's existing meters would not monitor and record steady state voltages and voltage variations as required by clause 4.2.6 of the Distribution Code. This would impede CitiPower's ability to proactively monitor energy supply quality and to address any customer complaints.	Installation of power quality meters To monitor and record steady state voltages and voltage variations in compliance with clause 4.2.6 of the Distribution Code, CitiPower will need to install power quality meters on each bus at affected zone substations.

Table 9.8 Consequences of operating CitiPower's network in the next regulatory control period if the AER's Draft Determination regarding fault mitigation is affirmed

Table 9.9 below shows the activities described above in Table 9.8 that CitiPower has determined will be required to reduce the impact to customers and the safety of the field staff in the next regulatory control period if the AER affirms its Draft Determination, as well as the level of forecast capex for each activity.

Table 9.9 also shows the development costs that CitiPower has identified will be required to implement the auto reclose and voltage control activities in the next regulatory control period. These costs are based on designing and programming modern digital logic solutions for management of auto reclose and voltage control schemes. Previous schemes have been deployed on discrete, secondary system components with hard wiring. This is now obsolete technology and cannot provide an efficient solution with the flexibility to apply to the variety of substations that CitiPower will be required to extend its auto reclose and voltage control activities to in the next regulatory control period.

ZSS	Capacitor bank module reduction ($'000)	Loading balance ($'000)	Auto close scheme ($'000)	Voltage control ($'000)	Remote control inhibit of feeder protection ($000)	Remote control load transfer ($'000)	Power Quality Meters ($'000)
Development costs			500	200			
Transformer circuit breaker open							
CL - Camberwell	-	-	150	-	-	-	-

ZSS	Capacitor bank module reduction ($'000)	Loading balance ($'000)	Auto close scheme ($'000)	Voltage control ($'000)	Remote control inhibit of feeder protection ($000)	Remote control load transfer ($'000)	Power Quality Meters ($'000)
RP - Russell Place (CBD)	-	-	150	-	-	-	-
SO - South Melbourne	-	-	150	-	-	-	-
TK - Toorak	-	-	150	-	-	-	-
Single bus tie circuit breaker open							
E - Port Melbourne	0	0	0	150	40	0	84
J - Spencer Street (CBD)	0	0	150	150	43	0	84
LS - Laurens Street	10	0	150	150	60	0	84
SK - St Kilda	10	0	150	150	57	0	84
VM - Victoria Market (CBD)	10	0	150	150	107	0	84
WA - Celestial Place (CBD)	10	0	150	150	107	0	84
FB - Fishermen's Bend	10	0	150	150	53	0	84
FR - Flinders and Ramsden Streets (CBD)	0	0	0	0	33	0	84
MG - Montague	10	0	150	150	53	0	84
MP - McIlwraith Place (CBD)	10	0	150	150	173	0	84
JA - Little Bourke Street (CBD)	10	0	150	150	47	0	84

ZSS	Capacitor bank module reduction ($'000)	Loading balance ($'000)	Auto close scheme ($'000)	Voltage control ($'000)	Remote control inhibit of feeder protection ($000)	Remote control load transfer ($'000)	Power Quality Meters ($'000)
BC (with 3rd Tx) - Balaclava	10	200	150	150	43	0	84
WB - West Brunswick	0	0	0	0	37	0	84
Two bus tie circuit breakers open							
LQ - Little Queen Street (CBD)	10	0	150	150	145	4300	96
NR - North Richmond	0	0	150	150	90	300	96
	100	200	2900	2150	1088	4600	1284
Total	**12322**						

Table 9.9 Activities CitiPower will be required to undertake in the next regulatory control period given the AER's Draft Determination regarding fault mitigation ($2010, excluding overheads and escalation)

In addition to the above, the operation of a tightly meshed network is increasingly compromised by segmentation and requires more complex operating procedures, particularly when transferring load. The segregation of CitiPower's 11kV network would mean that CitiPower would have to operate and switch the network in a different manner to that which it was designed. The complexity for operational staff also increases as the procedure for switching feeders from different buses requires the suppression of feeder protection at the zone substation exits.

Zone substation secondary systems replacement

CitiPower maintains that its zone substation secondary systems replacement reasonably reflects the capex criteria.

In its Draft Determination, the AER did not consider the detail provided in respect of each of the material reliability and quality maintained programs submitted by CitiPower to the AER by email on 26 February 2010. Each of the programs are driven by unique circumstances and risks. As noted above, further material program templates are included in Attachment 164 to this Revised Regulatory Proposal. These templates should allow the

AER to satisfy itself that the proposed expenditure is required in the next regulatory control period.

The zone substation secondary equipment on CitiPower's network is becoming technically obsolete and thus requires replacement. The AER's Repex Model is not capable of taking this into account. As noted by PB, in its review of the AER's Repex Model:[729]

> '*Due to replacement [being] driven by factors other than age, it is not clear how the Repex model is able to estimate replacements that are not related to time based deterioration (e.g. technical obsolescence, changes in statutory obligations, parts availability, etc)*'

Accordingly, rather than simply substituting the forecasts prepared by Nuttall Consulting using the Repex Model, the AER must consider the circumstances and risks driving each of the reliability and quality maintained programs.

The risks driving CitiPower's proposed zone substation secondary systems replacement can be grouped into three broad categories:

- maintaining network risks and reliability through the next regulatory control period (consistent with clauses 6.5.7(a)(3) and (4) of the Rules);
- maintaining the network's OHS and public safety (consistent with clause 6.5.7(a)(4) of the Rules); and
- ensuring compliance with obligations under the Electricity System Code[730] (and the associated High Voltage Protection Sub-Code[731]), Chapter 5 of the Rules[732] and the Distribution Code (consistent with clause 6.5.7(a)(2) of the Rules).

These risks, and how they drive key zone substations replacement programs, are discussed in further detail below.

As noted above, the AER raised concerns in respect of CitiPower's proposed relay replacement.

In commenting that the level of replacement in the next period does not appear to be significantly different to the level in 2007-08,[733] Nuttall Consulting has misunderstood the difference between relays and protection schemes. Nuttall Consulting has made a comparison between the average number of **relays** replaced in 2007-08 with the proposed number **schemes** to be replaced in 2011-15.

In most old electro mechanical feeder protection schemes, there are typically discrete relays connected to measure current on each of the three phases (red, white and blue) and a separate relay to measure the current flowing to earth. These relays provide the ability to detect network faults where high current flows occur and signals are sent to circuit breakers

[729] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p38.
[730] Attachment 167 to this Revised Regulatory Proposal.
[731] CitiPower observes that the HV Protection Sub-Code was only established in July 2008, and thus compliance expenditure associated with this Sub-Code would not be included in the 2006-08 period examined by Nuttall Consulting.
[732] CitiPower notes that it is required to comply with Chapter 5 of the Rules from 1 January 2011: clause 9.7 of the Rules.
[733] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p113.

to isolate the fault. With modern relays, however, the discrete relays are built into a single protection relay that is referred to as a protection scheme.

As noted in the program template provided to the AER, across CitiPower's network, there are on average two relays for each scheme.[734] The template provided to the AER on 26 February 2010 indicates that CitiPower is proposing to increase from replacing an average of 38.35 schemes per annum in 2007-08 (or an average of 46 schemes per annum across 2006-10) to replacing approximately 130 relays (or 65 schemes) per annum in the next regulatory control period.[735] This is a significant increase in proposed replacement.

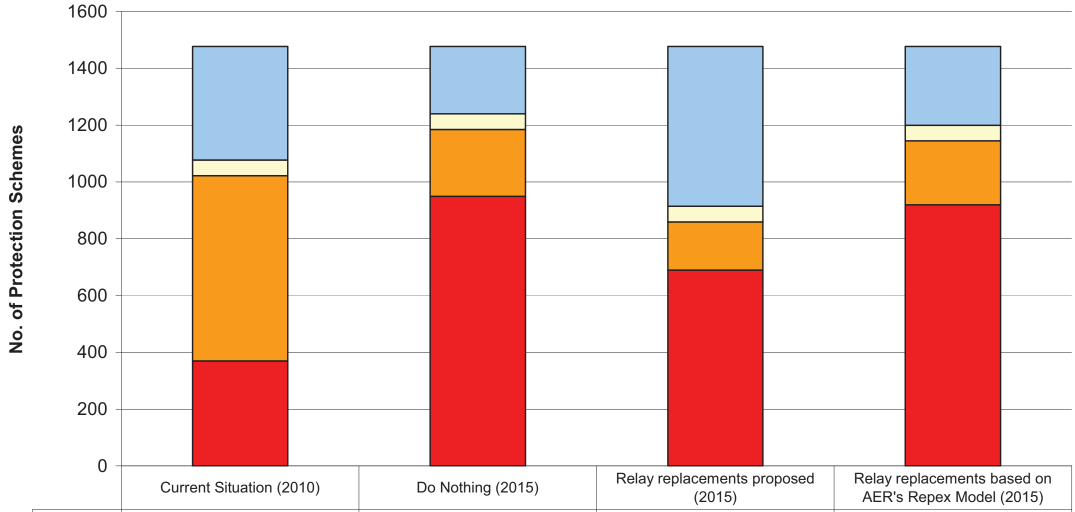
The increase in relay replacement in the next regulatory control period is driven by CitiPower's RCM analysis, which is reflected in CitiPower's Protection Equipment (Relays) Asset Management Plan.[736] The RCM process involves assessing the risk of failure that each relay presents to the business. An overall risk score is calculated for each relay taking into account a range of risk factors (which are set out in the Protection Equipment (Relays) Asset Management Plan[737]). CitiPower notes that one of these risks is a lack of product support (manufacturers support for hardware and software is limited to approximately 15 years, after which time, manufacturers do not provide updated software configuration and maintenance of the relays becomes problematic).[738]

In the next regulatory control period, CitiPower is proposing to replace relays that were assigned a 'very high' overall risk score (assets which require replacement within 0-4 years) (of which approximately 725 have been identified), as well as relays that should be replaced to ensure that isolated relays are not left unchanged as the program is implemented.[739]

Failure of one type of relay can affect hundreds of circuits in CitiPower's network, jeopardising the high reliability level of the network and affecting a large number of customers.[740] CitiPower estimates, on the replacement capex included in its Revised Regulatory Proposal, the number of relays in the 'very high' risk category would increase to 320 (shown in Figure 9.1 below) and there would be marginal increase in relay failures.[741] CitiPower maintains, however, that it would remain compliant with the 'good asset management' obligations in clause 3 of the Distribution Code. On the AER's Draft Determination, however, the number of relays in the 'very high' risk category would increase by 550 to 920.[742] This is also shown in Figure 9.1 below. CitiPower considers that

[734] Document titled 'CP 156 – Ageing_Unreliable Relay Replacement' (provided to the AER 26 February 2010), p2.
[735] Document titled 'CP 156 – Ageing_Unreliable Relay Replacement' (provided to the AER 26 February 2010), p1.
[736] CitiPower, Protection Equipment (Relays) Asset Management Plan, 26 December 2009 (provided to the AER by email on 5 March 2010).
[737] CitiPower, Protection Equipment (Relays) Asset Management Plan, 26 December 2009 (provided to the AER by email on 5 March 2010), pp21-22.
[738] CitiPower, Protection Equipment (Relays) Asset Management Plan, 26 December 2009 (provided to the AER by email on 5 March 2010), p21.
[739] Document titled 'CP 156 – Ageing_Unreliable Relay Replacement' (provided to the AER by email on 5 March 2010); CitiPower, Protection Equipment (Relays) Asset Management Plan, 26 December 2009 (provided to the AER by email on 5 March 2010), p23.
[740] CitiPower, Protection Equipment (Relays) Asset Management Plan, 26 December 2009 (provided to the AER 5 March 2010), p
[741] See the material program template 'Ageing/Unreliable Relay Replacement Program – Zone Substations' (included in Attachment 164 to this Revised Regulatory Proposal).
[742] See the material program template 'Ageing/Unreliable Relay Replacement Program – Zone Substations' (included in Attachment 164 to this Revised Regulatory Proposal).

this increase in the number of relays in this category would be inconsistent with the Distribution Code 'good asset management' obligations.



	Current Situation (2010)	Do Nothing (2015)	Relay replacements proposed (2015)	Relay replacements based on AER's Repex Model (2015)
Low	401	238	563	278
Moderate	55	55	55	55
High	652	235	170	225
Very High	370	950	690	920

Relay Replacement Rate

Figure 9.1 CitiPower relay risk profile (2010 and 2015)

On the information set out above, CitiPower submits that its proposed relay replacement program in the next regulatory control is prudent and efficient.

Regarding the other zone substation secondary system replacement programs reflected in CitiPower's 2011-15 forecasts, CitiPower maintains that these are economically justified or are required to respond to increased risk on the network and (where relevant) reflect the applicable asset management plans. In addition to the further material programs templates included in Attachment 164 to this Revised Regulatory Proposal, Table 9.10 below sets out some of the major programs reflected in the 2011-15 forecast, including the circumstances and risks driving each program.

Program	Explanation
Augmentation associated with SP AusNet projects[743]	SP AusNet is proposing to upgrade its Richmond terminal station and WMTS. SP AusNet's works will involve 66kV asset rebuilds. To maintain the reliability and security of the transmission connection points, all 66kV lines protection schemes associated with these works at connected zone substations must be re-established. That is, CitiPower's program includes non-discretionary replacement of x and y schemes and CitiPower's zone substations that communicate to Richmond terminal station and WMTS (27 lines in total over the next regulatory control period. The works are required to ensure the protection and communications assets of SP AusNet and CitiPower are co-ordinated and compatible and are not compromised. If CitiPower cannot complete the works, SP AusNet would be unable to complete the refurbishment of Richmond terminal station and WMTS. Delaying the works will mean that CitiPower is unable to

[743] See document titled 'CP 156 – Augmentation Associated with SPAusNet Projects' (provided to the AER by email on 26 February 2010) and material program template 'Augmentation Associated with SP AusNet Projects' (included in Attachment 164 to this Revised Regulatory Proposal).

	maintain the network risks and reliability. For example, there would be an increase in the risk of security of supply issues, extended fault clearing times, zone substation outages, extended time outages, increased damage to plant and an increase in health and safety risks to employees and the public.
Replacement of ageing switch controllers[744]	This program involves the replacement of CitiPower's switch controllers. Typically, switch controllers last 10 to 15 years in the field before requiring upgrading. Upgrading is required due to failure of microprocessors and communications equipment due to the harsh environments in which they operate and the fact that product support usually ends after about 10 years. CitiPower generally has one type of switch controller installed in its network, namely the GCR300 gas switch controller. It was introduced into the network over the last 10 years and is now approaching the end of its life. CitiPower is proposing to replace 15 switch controllers per year in the next regulatory control period (this will see the replacement of approximately 75 per cent of CitiPower's switch controller population). Failure of a switch controller may result in the loss of control of that particular site.
DC supplies, amp hour capacity and fusing upgrades for zone substations[745]	This program is required to ensure that DC capacity is available to run zone substation protection and control systems not only for short duration outages of up to 8 to 12 hours but for longer outages of up to 24 or 48 hours. Where the DC power fails, all protection control systems at zone substations cease to operate and the zone substation cannot be used as a supply point until the DC systems are restored. An analysis of battery systems has shown that a significant number of stations do not have adequate backup capacity. This project aims to commence a program to upgrade the highest risk sites. CitiPower's proposed program is required to maintain network reliability and security of supply (by maintaining fault clearing times) and to maintain occupational health and safety and public safety. The proposed program is also required to achieve compliance with clause 2.6 of the HV Protection Sub-Code. CitiPower notes that without the proposed program, extended fault clearing times would result in reduced network reliability and an increase in potential risks to the public. The public would also face increased risks through damage to network assets and CitiPower would also be unable to comply with clause 2.6 of the HV Protection Sub-Code.
Control room modifications[746]	CitiPower has a number of ageing control rooms, which can restrict the deployment of additional equipment and systems for CitiPower's proposed protection and control works. For example, older control rooms may: • not allow for safe access to panels and equipment; • not have adequate space to house new equipment; • give rise to difficulties at commissioning due to the space constraints of temporary cubicles; • have inadequate cable trenches that restrict the level of cabling that can be deployed; and • not adequately manage humidity and condensation. Historically, control room modifications have been put off and protection changes forced into the limited spaces available. This has led to poor arrangements and difficult operating testing

[744] See document titled 'CP 156 – Replacement of Ageing Switch Controllers' (provided to the AER by email on 26 February 2010).
[745] See document titled 'CP 156 – DC Supplies, AmpHour Capacity and Fusing Upgrades' (provided to the AER by email on 26 February 2010) and material program template 'Replacement Battery Banks and Chargers' (included in Attachment 164 to this Revised Regulatory Proposal).
[746] See document titled 'CP 156 – Control Room Modification' provided to the AER by email on 26 February 2010.

	environments. Deferral is not longer possible due to likely health and safety risks from the limited space now available. Upgrades have been proposed to ensure a safe, secure and effective control room environment.
Upgrade ageing relays in customer indoor substations and switching stations[747]	This program involves replacement of end of life high risk relays at indoor distribution substations within customer owned buildings, and switching stations. There are over 800 indoor substations in CitiPower's distribution network and a large number of switching stations. In recent years, failures of electronic relays in CBD substations have left CBD buildings without supply. The zone substation relay replacement program does not include replacements of relays within these distribution substations and switching station sites. This program is therefore necessary to replace high risk relays at indoor substations and switching stations and thereby maintain the integrity and safety of CitiPower's distribution network. The work to be undertaken is driven by the condition of the relays and has been identified through relay failures in distribution substations on the network. The proposed program will maintain the reliability of CitiPower's network by replacing equipment approaching the end of its life. It will also ensure that risks to public safety from failed primary protection in substations within large CBD buildings are not increased. CitiPower considers this will ensure compliance with its 'good asset management' obligations under clause 3 of the Distribution Code. However, without the proposed program, CitiPower would expect relay failure rates to increase, resulting in higher occurrences of more extensive network outages. There would also be an increase in the risks to public safety from failed primary protection in substations within large CBD buildings. Finally, CitiPower would risk non-compliance with its 'good asset management' obligations under clause 3 of the Distribution Code.
Duplicate protection on buses and circuit breaker backup[748]	Duplicate protection on 66kV buses lowers the risk of zone substation outages and provides flexibility and security when undertaking maintenance. If there is no circuit breaker backup, protection devices further removed from the fault will need to be activated to clear the fault. Both are consistent with good industry practice. Duplicate protection on 66kV buses and circuit breaker backup schemes have not been established across CitiPower's 66kV network. CitiPower has proposed these works to coincide with other proposed protection works. These works are required to achieve compliance with clauses 3.2, 3.5.2.1 and 3.5.2.3 of the HV Protection Sub-Code and clause S5.3a.6 of the Rules. Without the proposed program, CitiPower would not be able to achieve compliance with these mandatory obligations.
Replacing ALMOS system with Ethernet PLC units[749]	This program is driven by prudency and involves the replacement of ageing remote monitoring equipment at distribution substations around the CBD. CitiPower notes that there is no longer manufacturer support for the equipment CitiPower is proposing to replace. There are approximately 400 sites in the CBD that require upgrading over the next two regulatory control periods. CitiPower is proposing to replace half of these in the next regulatory control period. Failure of remote monitoring equipment may result in zone substation failures and customer outages. This program is required to allow CitiPower to maintain reliability by replacing equipment

[747] Document titled 'CP 156 – Upgrade Aging Relays in Customer Indoor Substations' (provided to the AER by email on 26 February 2010).
[748] Document titled 'CP 156 – Duplicate Protection on Buses and CB Backup' (provided to the AER by email on 26 February 2010) and material program template 'Duplicate Protection on Buses and Circuit Breaker Backup' (included in Attachment 164 to this Revised Regulatory Proposal).
[749] See document titled 'CP 156 – Replace Almos with Ethernet PLC Units' (provided to the AER 26 February 2010) and material project template 'Replace Almos with Ethernet PLC Units in Distribution Substations' (included in Attachment 164 to this Revised Regulatory Proposal).

	that is approach the end of its life. CitiPower notes that this ensures compliance with its 'good asset management' obligations under clause 3 of the Distribution Code. Without the proposed program, CitiPower would not be able to replace units approaching the end of their life, and outage durations would increase as a result of an increase in the number of failed units. CitiPower would also risk non-compliance with its 'good asset management' obligations under clause 3 of the Distribution Code.
Auto reclose implementation program on 66kV & 22kV buses[750]	CitiPower is proposing auto reclose functionality on selected 66kV zone substations and lines. Auto reclose schemes allow the re-energisation of a line after a fault trip. Such schemes can provide a substantial improvement in the security of supply following a transient fault. Without auto reclose, assets can be opened for events that are transitory. In the case of zone substation buses, an extended outage may occur that could have been avoided. The restore time could also be significant as onsite checking of buses would need to occur before restoration. Currently, auto reclose schemes are not established across CitiPower's 66kV network. The move to establish these protection works will bring CitiPower's 66kV zone substation protection schemes into line with standard industry practice and is necessary to improve CitiPower's urban zone substation security. The proposed program will allow CitiPower to ensure compliance with clauses 7 and 9.1 of the HV Protection Sub-Code. Without the proposed program, however, CitiPower risks non-compliance in the next regulatory control period.
Secondary works associated with compliance around system fault level management[751]	This program involves the implementation of normally open auto close schemes and associated transformer management systems to allow systems fault levels to be managed within required fault level limits of existing zone substation and distribution network plant and equipment. Program work may involve the implementation of normally open auto close schemes to split an existing bus in two. By having the circuit breaker in a 'normally open' position under normal conditions the impedance is increased and the fault current levels are reduced. The auto-close functionality will then restore the customer load in the event of a transformer or bus outage. CitiPower has updated this program to reflect the AER's rejection of its fault level compliance program. This program is designed to maintain compliance with voltage requirements while operating a significantly greater number of segregated zone substation buses. CitiPower considers the program will ensure compliance with clause 4 of the Distribution Code. Without the proposed program, CitiPower would be unable to maintain voltage in accordance with the requirements in the Distribution Code and would not be able to comply with clause 4 of the Distribution Code.

Table 9.10 Key zone substation secondary system replacement programs included in CitiPower's Revised Regulatory Proposal

Nilsen LV air circuit breaker replacement

Contrary to the AER's suggestion that CitiPower has managed the risks in the current regulatory control period,[752] CitiPower does not consider that two failures in 2005 and 2007 can properly be considered as 'managing' the risks. CitiPower submits that the risks

[750] See document titled 'CP 156 –Auto Reclose Implementation on 66kV lines and Buses' (provided to the AER on 26 February 2010) and 'Auto Reclose Implementation Program on 66kV lines and Buses' (included in Attachment 164 to this Revised Regulatory Proposal).
[751] See material program template 'Secondary Works Associated with Fault Level Management' (included in Attachment 164 to this Revised Regulatory Proposal).
[752] AER, Draft Determination, pp351-2.

associated with the particular series of Nilsen LV air circuit breakers under consideration mean that the replacement program is justified.

CitiPower understands that the Nilsen LV air circuit breakers were last manufactured in the early 1970s, making the youngest of the assets nearly 40 years old. For switchgear of this type, a service period of 40 years is to be expected, however, beyond this time, it is viewed as approaching the end of its useful life. The two recent failures are indicative of the population reaching the end of its life. As a result, unless a prudent replacement program was established, more failures could be expected and at an increasing rate. This can be seen in Figure 9.2 below.

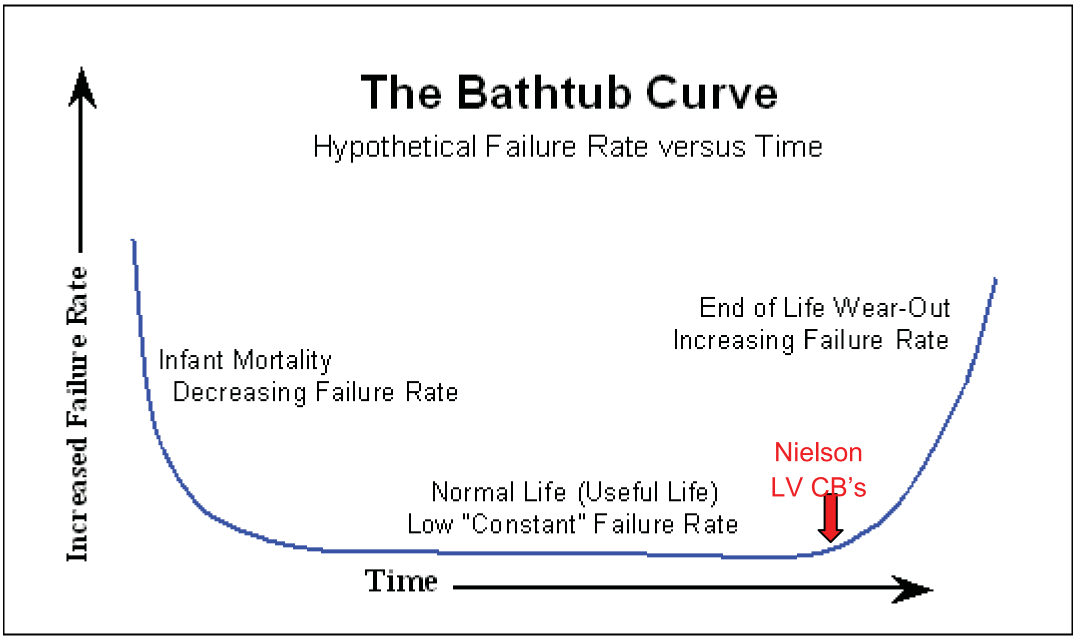


Figure 9.2 Point of the bathtub curve on which Nilsen LV air circuit breakers are situated[753]

CitiPower introduced its Network Asset Replacement Policy for 3000A LV Air Circuit Breakers – Type Nilsen "AB" Series only in 2009,[754] after detailed investigations were conducted into the two failures.

The asset management plan identifies the number of circuit breakers requiring replacement (107 in service at the end of 2009).[755] Given CitiPower proposed to replace 10 circuit breakers in 2010, only 97 circuit breakers remain to be replaced in 2011-15.[756] CitiPower's proposed expenditure (as outlined in the material program template included in Attachment 164 to this Revised Regulatory Proposal) is therefore consistent with its asset management plan.

[753] More detail regarding the bathtub curve is available in the articles by Dennis J. Wilkins, The Bathtub Curve and Product Failure Behavior (Attachments 264 and 265 to this Revised Regulatory Proposal).
[754] CitiPower, Network Asset Replacement Policy for 3000A LV Air Circuit Breakers – Type Nilsen "AB" Series, 25 November 2009 (Attachment C0108 to the Initial Regulatory Proposal).
[755] CitiPower, Network Asset Replacement Policy for 3000A LV Air Circuit Breakers – Type Nilsen "AB" Series, 25 November 2009 (Attachment C0108 to the Initial Regulatory Proposal), Appendix A.
[756] See material project template 'Replacement of Nilsen LV air circuit breakers' (included in Attachment 164 to this Revised Regulatory Proposal).

Given CitiPower's historic expenditure does not include reliability and quality maintained capex in 2006-08 for Nilsen circuit breaker replacement, and only reflects a limited degree of expenditure in 2009, Citipower notes that historical expenditure will not provide sufficient expenditure for this program in 2011-15.

The AER's Draft Determination reduced the proposed capex for function code 143 by $11m ($2010), from $15.1m to $4.1m. If $4.1m ($2010) was split pro-rata across CitiPower's proposed programs, then only around 27 Nilsen LV air circuit breakers (or around one quarter of the population) could be expected to be replaced by the end of 2015. To the extent they do not fail in the next regulatory control period, 73 units would remain in service, posing significant risks. At this rate of replacement, it would take a further fifteen years beyond 2015, that is, until 2030 to replace the entirety of the population. This would make the last of these units in service around 60 years old and thus posing an unacceptable risk.

Reliability replacement

CitiPower maintains that its proposed reliability replacement programs and associated capex in the next regulatory control period are prudent and efficient.

Proposing relatively modest expenditure to address small pockets of the network experiencing levels of reliability well below average levels ensure that customers in the worst served areas are brought closer to the average levels of reliability.

CitiPower believes that this level of expenditure is required to ensure compliance with CitiPower's obligation to *'meet reasonable customer expectations of reliability of supply'* in clause 5.2 of the Distribution Code.

In its independent review of the Draft Determination in respect of reliability and quality maintained capex, PB noted that Nuttall Consulting did not identify how reliability replacement expenditure has been allocated historically and has not supported the rejection of this expenditure with any analysis of the fundamental need for the proposed expenditure.[757] PB considered that, given the alignment of CitiPower's proposed reliability replacement expenditure with the Repex Model results, the proposed expenditure should be accepted.[758]

To assist the AER with its consideration of CitiPower's Revised Regulatory Proposal, CitiPower provides further details in respect of each of its reliability replacement programs in Table 9.11 below.

Program	Explanation
Animal mitigation[759]	These works include installation of covers, guards and devices on exposed apparatus to prevent inadvertent contact of live high voltage equipment and lines by animals and birds. The program is targeted at those areas of the network where some customers have been receiving a level of service well below the network average reliability. Each year, a new part of the network is assessed as part of a survey. The results of the survey are used to inform work in the following

[757] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p19.
[758] PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p19.
[759] See document titled 'CP 166 – Animal Mitigation' (provided to the AER by email on 3 March 2010).

	years (within a five year period). CitiPower is proposing works consistent with its Pole Top Structures Asset Management Plan (Attachment C0111 to the Initial Regulatory Proposal). The works are required to maintain reliability on these parts of the network.
HV fuse installation on spur lines[760]	This program involves installing high voltage fuses on spur lines. A spur line is a line off a feeder backbone on the network. Typically, the way in which CitiPower's network was planned and built means that the substations have HV fuses but there are not HV lines or spur fuses. The program is targeted at those areas of the network where some customers have been receiving a level of service well below the network average reliability. The works involve removing fuses at the substation and installing them at the beginning of the spur line. This provides protection from falling trees on the spur line in addition to outages at the substation (as opposed to just providing protection from substation faults). It therefore offers greater protection against outages off the feeder. If this work is not carried out and a fault occurs on the spur line, the next protection devices to clear the fault may be at the zone substation. This means that a larger number of customers may be affected. The program will be targeted at areas where there have been significant localised reliability incidents to the spur line. Citipower is proposing to install two HV fuses per year. The works are required to address reliability issues on these worst served parts of the network.
HV line covering[761]	This program involves the installation of covering and insulation tubing on bare HV overhead lines to reduce the risk of vegetation initiated faults. The program is targeted at those areas of the network where some customers have been receiving a level of service well below the network average reliability. Vegetation surveys are undertaken every year which identify significant or dangerous trees (i.e. trees which could pose a risk in the case of adverse weather conditions, for example, because a branch could fall and cause a fault). To address this risk, CitiPower is proposing to install split tubing or insulated tubing over the conductor in the vicinity of the vegetation that can't otherwise be mitigated by other vegetation clearances. The works are required to address reliability issues on these worst served parts of the network.
Installation of CCT conductor[762]	This program involves the replacement of HV bare conductor with CCT conductor. The CCT conductor is covered with thick insulation and installed to prevent outages in areas with very high vegetation exposure to reduce the risk of vegetation initiated faults and to provide protection for people in the area against exposure to electricity where vegetation may contact live lines (for example, children climbing trees). The program is targeted at those areas of the network where some customers have been receiving a level of service well below the network average reliability. The program is designed to target areas where significant length of line is exposed. CCT conductor is used rather than split tubing where the spans of exposure are longer and in order to address the de-rating that occurs with the installation of tubing. CitiPower has trialled the replacement of HV bare conductor with CCT conductor on a section of Croydon Road, Surrey Hills, and a section of Kooyong Road, Armadale. The trials were successful and since then small sections have been converted on an opportunity basis in conjunction with augmentation and relocation projects. CitiPower is proposing to under one project per year (similar in size to the Croydon Road, Surrey

760 See document titled 'CP 166 – HV Fuse Installation on Spur Lines' (provided to the AER by email on 3 March 2010).
761 See document titled 'CP 166 – HV Line Covering' (provided to the AER by email on 3 March 2010).
762 See document titled 'CP 166 – installation of CCT Conductor' (provided to the AER by email on 3 March 2010).

	Hills project, i.e. around 1.3km) over the next regulatory control period. The works are required to address reliability issues on these worst served parts of the network.
Installation of LV spreaders[763]	This program involves the installation of LV spreaders in the remaining sections of the network that do not have them installed. The program is targeted at those areas of the network where some customers have been receiving a level of service well below the network average reliability. If conductors clash then one or more fuses may blow resulting in customer interruptions. LV spreaders keep the bare mains conductors separated to prevent clashing due to weather and other external influences. The locations for spreader installations will be identified from inspections and surveys including the scheduled visual high voltage feeder visual inspections (a scheduled maintenance activity). It is estimated that at the forecast rate this program will extend just beyond the next regulatory control period. The works are required to address reliability issues on these worst served parts of the network.
Remote alarm and fault indication at substations with restricted access[764]	This program involves the installation of remove alarm and fault indication at distribution substations with restricted access. Restricted or obstructed access may involve locked substations where the keys are housed at an alternative location and stations that may be positioned off main roads requiring pedestrian access by operating personnel. This issue is a legacy of past design and planning practices regarding the location of, and access to, distribution substations on customer's premises. The proposed works will generally involve the fitting of remote indication (flashing lights or mechanical indicators) to improve the access to fault indicator targets. It may also include improvements to access by standardisation of keys and locks that have been installed by customers since the substation was commissioned. The standardisation of keys will shorten patrol times where existing keys have to be sought from remote key lockers and thus reduce restoration times following a fault. The program primarily involves work at distribution substations on the fringes of the CBD network where there is no opportunity for remote communications and SCADA. The works will reduce the risk of long restoration times and reliability outliers for small sections of customers. Safety for operating personnel will also be increased as the risk of inadvertently re-energising faulted lines and cables is reduced. CitiPower has forecast the works taking place at two sites per year in the next regulatory control period. This level of activity is considered to provide a pragmatic approach to existing obstructed access substations taking available resources and other work programs into account.

Table 9.11 Key reliability programs included in CitiPower's Revised Regulatory Proposal

9.9.4 CitiPower's Revised Regulatory Proposal

The reliability, quality and maintained capex forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 9.12 below.

	$'000 (real 2010)					
Expenditure category	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
Reliability and quality maintained	46,132	50,777	52,043	56,656	60,766	**266,374**

Table 9.12 Reliability and quality maintained capex forecasts included in CitiPower's Revised Regulatory Proposal

763 See document titled 'CP 166 – Installation of LV Spreaders' (provided to the AER by email on 3 March 2010).
764 See document titled 'CP 166 – Remote Alarm Indication at Obstructed Access Substations' (provided to the AER by email on 3 March 2010).

9.10 Environmental, safety and legal capex

9.10.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower proposed capex relating to capital works to ensure that it complies with all applicable environmental, electrical safety, regulatory and other Victorian and national legislative obligations.[765]

CitiPower indicated that the main factor driving the increase in this category of expenditure from 2006-10 capex was increased noise mitigation at zone sub-stations.[766]

9.10.2 AER's Draft Determination

In its Draft Determination, the AER observed that Victorian DNSPs actual capex tends to follow a gradually increasing trend.[767]

The AER concluded that:[768]

- the Victorian DNSPs have not demonstrated there will be material changes to their compliance with environmental legislation and regulations or safety legislation and regulations in the next regulatory control period;
- the Victorian DNSPs are currently complying with their environmental, safety and legal obligations; and
- accordingly, the associated costs would be reflected in the historical capex for this category.

The AER indicated that, because EPA Victoria and the ESV have encouraged DNSPs to adopt a *'risk management approach to compliance'*, the AER expected the DNSPs to provide risk assessments in support of their proposed expenditure.[769] The AER noted the project explanations provided by CitiPower, but indicated these were not linked to any risk assessment in support of an overall works program.[770]

The AER therefore rejected CitiPower's proposed environmental, safety and legal capex forecasts and substituted amounts based on a continuation of historical trend in this capex category.[771] In identifying the historical trend, the AER used 2004-08 data (excluding 2009 and 2010 on the basis that the data before the AER was forecast data only).[772]

9.10.3 CitiPower's response to the AER's Draft Determination

CitiPower does not contest the AER's Draft Determination with respect to environmental, safety and legal capex. However, for the reasons outlined in the 'General issues' section above, CitiPower considers that the AER should include 2009 actual data:

- in its trend analysis; and

[765] Initial Regulatory Proposal, p118.
[766] Initial Regulatory Proposal, p126.
[767] AER, Draft Determination, p399.
[768] AER, Draft Determination, p402.
[769] AER, Draft Determination, p401.
[770] AER, Draft Determination, p402.
[771] AER, Draft Determination, pp394-404.
[772] AER, Draft Determination, p400.

- in forecasting the environmental, legal and safety capex required in the next regulatory control period by reference to historical expenditure.

CitiPower notes that, as demonstrated by Figure 9.3 below, when data beyond 2004-08 (including 2009 actual data) is incorporated into the analysis, the AER's conclusion that CitiPower's actual capex follows a gradually increasing trend is less compelling.

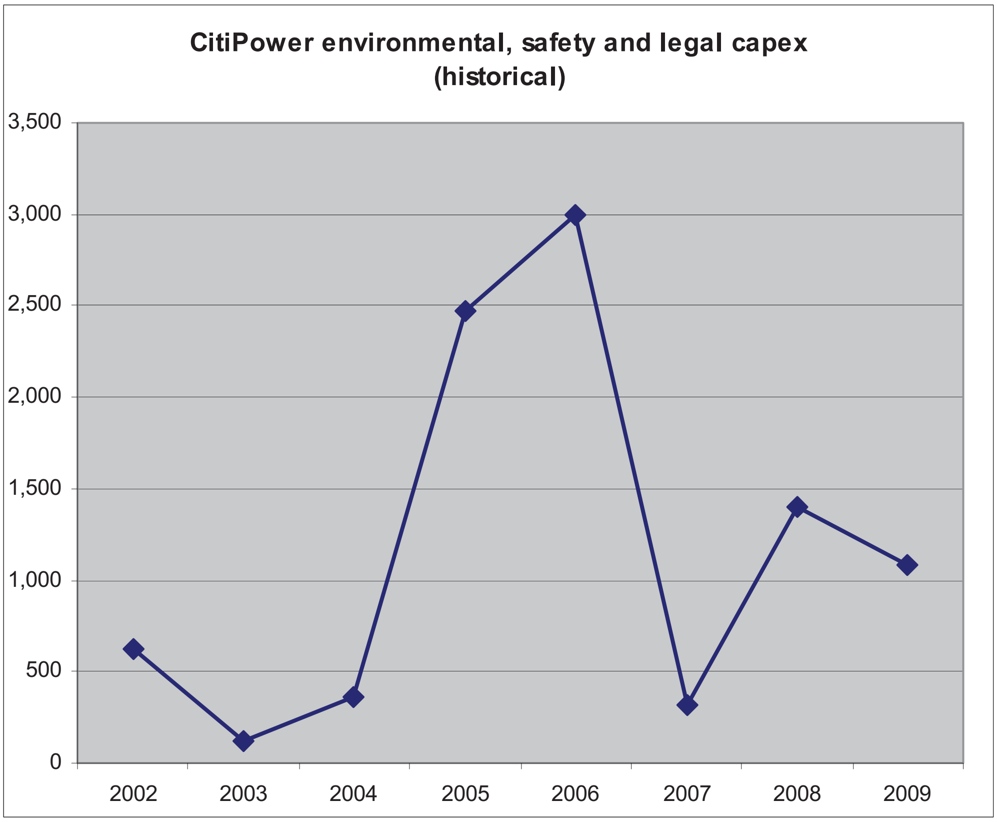


Figure 9.3 CitiPower's historical environmental, safety and legal capex (real $'000)

CitiPower notes that, if the AER makes its Final Determination consistent with its Draft Determination, CitiPower will not be in a position to complete all of the noise works contemplated in its Initial Regulatory Proposal.[773]

CitiPower also rejects the AER's suggestion that because the EPA and ESCV have encouraged DNSPs to adopt a 'risk management approach to compliance', DNSPs should provide risk assessments in support of their proposed expenditure. As noted in the 'General issues' section above, this is not legally permissible because achievement of the capex objectives includes compliance with all applicable regulatory obligations or requirements associated with the provision of standard control services (clause 6.5.7(a) of the Rules). Accordingly, should a DNSP require capex to comply with an obligation, it should suffice to satisfy the AER, acting reasonably, that the capex would be required by a prudent and efficient operator to achieve the capex objectives for that DNSP to demonstrate that its proposed capex is the lowest means of achieving compliance.

[773] Initial Regulatory Proposal, pp119-20.

Finally, as discussed in further detail in Chapters 6 and 17 of this Revised Regulatory Proposal, CitiPower considers the plans submitted under the Electrical Safety Management Regulations should be addressed by the AER as a nominated pass through.

9.10.4 CitiPower Revised Regulatory Proposal

The environmental, safety and legal capex forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 9.13 below.

	$'000 (real 2010)					
Expenditure category	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
Environmental, safety & legal	1,440	1,465	1,474	1,499	1,532	**7,411**

Table 9.13 Environmental, safety and legal capex forecasts included in CitiPower's Revised Regulatory Proposal

9.11 SCADA and network control capex

9.11.1 CitiPower's Initial Regulatory Proposal

CitiPower's Initial Regulatory Proposal included SCADA and network control capex.[774] The proposed SCADA and network control capex program included provision for the following:[775]

- continuation of the installation of new protection and control communications infrastructure, which CitiPower and CitiPower commenced as a joint project in the current regulatory control period. A summary of the requirements of this Program was set out in CitiPower and CitiPower's Network Protection and Control Communications Strategy 2009 - 2014 (included as Attachment P0030 to the Initial Regulatory Proposal);
- installation of DMS field devices, which are network data collection devices that sit on poles or in substations that provide interface with electrical assets; and
- increased substation monitoring and automation investments.

CitiPower provided SCADA and network control material program templates to the AER by email on 9 March 2010. These templates detailed the range and rationale for the expenditure in this capex category at the program level.

9.11.2 AER's Draft Determination

In its Draft Determination, the AER observed that Victorian DNSPs actual capex tends to follow a gradually increasing trend.[776] The AER also commented that each DNSP underspent its benchmark allowance in the current regulatory control period.[777]

The AER indicated that CitiPower had not justified the significant increase in forecast SCADA and network control required for the next regulatory control period.[778] The AER commented that, because DNSPs have discretion to prioritise their work program, each

[774] Initial Regulatory Proposal, pp126-34.
[775] Initial Regulatory Proposal, p128.
[776] AER, Draft Determination, p409.
[777] AER, Draft Determination, p410.
[778] AER, Draft Determination, pp411-2.

DNSP underspent relative to the ESCV benchmark allowance on the basis that it considered it efficient to do so.[779]

In assessing CitiPower's proposed SCADA and network control capex, Nuttall Consulting stated that the DMS field devices installation program identified by CitiPower is captured in proposed non-network – IT capex.[780] Consequently, Nuttall Consulting did not assess it in the SCADA and network control section of its report[781] and the AER did not refer to the installation of the DMS field devices in its Draft Determination.[782]

The AER indicated that CitiPower and Powercor Australia had not quantified the costs and benefits of their joint installation of new protection and control communications infrastructure project or justified the scope and timing of the individual projects proposed under it.[783] The AER also did not consider that CitiPower had linked the majority of the proposed projects to the Network Protection and Control Communications Strategy 2009-2014.[784]

The AER therefore rejected CitiPower's proposed SCADA and network control forecasts and substituted amounts based on a continuation of historical trend in this capex category.[785] In identifying the historical trend, the AER used 2004-08 data (excluding 2009 and 2010 on the basis that the data before the AER was forecast data only).[786]

9.11.3 CitiPower's response to the AER's Draft Determination

For the reasons outlined in the 'General issues' section above, CitiPower considers that the AER should include 2009 actual data in its trend analysis and in determining an amount that is consistent with historical capex.

CitiPower notes that, as demonstrated by Figure 9.4 below, when data beyond 2004-08 (including 2009 actual data) is incorporated into the analysis, the AER's conclusion that CitiPower's actual capex follows a gradually increasing trend is less compelling.

[779] AER, Draft Determination, p411.
[780] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p132.
[781] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p132.
[782] AER, Draft Determination, p411.
[783] AER, Draft Determination, p411.
[784] AER, Draft Determination, p411.
[785] AER, Draft Determination, pp409-13.
[786] AER, Draft Determination, p409.

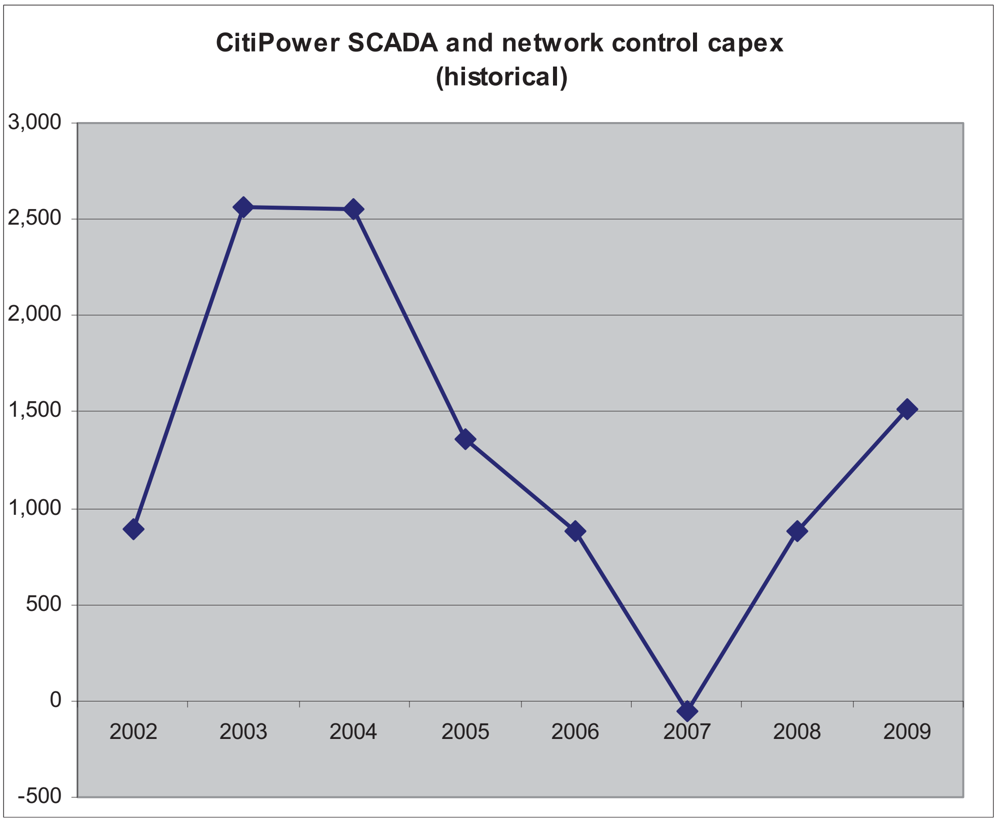


Figure 9.4 CitiPower's historical SCADA and network control capex

In assessing its proposed SCADA and network control capex, the AER did not consider the circumstances and risks facing CitiPower in the next regulatory control period. CitiPower contends that its SCADA and network control programs are required in the next regulatory control period. The risks driving these programs can be grouped into three broad categories:

- maintaining network risks and reliability through the next regulatory control period (consistent with clauses 6.5.7(a)(3) and (4) of the Rules);
- maintaining the network's occupational health and safety and public safety (consistent with clause 6.5.7(a)(4) of the Rules); and
- ensuring compliance with obligations under the Electricity System Code[787] (and the associated HV Protection Sub-Code), Chapter 5 of the Rules[788] and the Distribution Code (consistent with clause 6.5.7(a)(2) of the Rules).

These risks are discussed in relation to CitiPower's proposed SCADA and network control programs in more detail below, after the specific issues raised by Nuttall Consulting and the AER are addressed.

9.11.3.1 DMS field devices

Nuttall Consulting is correct in stating that expenditure on the DMS in the next regulatory control period is included in CitiPower's non-network – IT capex. This is because the DMS is part of the IT system. However, Nuttall Consulting erred in finding that the implementation of the DMS field devices (network data collection field devices) is also

[787] Attachment 167 to this Revised Regulatory Proposal.
[788] CitiPower notes that it is required to comply with Chapter 5 of the Rules from 1 January 2011.

covered by non-network – IT capex.[789] This expenditure is included in the SCADA capital expenditure because it directly relates to the roll out of DMS field devices.

To further clarify, it is the capex on the acquisition of the DMS itself that is included in CitiPower's non-network - IT capex. The DMS is designed to support and extend CitiPower's SCADA operations and will enhance the ability to display and utilise data captured by and transmitted from the DMS field devices. By contrast, the capex included in the SCADA and other network control capex forecasts relates to the roll-out of DMS field devices (i.e. the cost of acquiring and installing the network data collection devices) rather than the implementation of the DMS itself.

9.11.3.2 Reasons for underspend in the current regulatory control period

The AER's conclusion that CitiPower underspent on SCADA and network control capex in relation to the ESCV's benchmark allowance because it considered it efficient to do so is erroneous. The deferral of much of CitiPower's SCADA and network control capex in the current regulatory control period was for reasons other than efficiency.

For example, there was a delay in the installation of the DMS field devices due to delays in the implementation of the DMS. The implementation of the DMS was delayed by complications arising with essential lead-in projects, including the following:

- the migration of both CitiPower and Powercor Australia's different versions of GIS to a common and updated platform;
- the migration of both CitiPower and Powercor Australia's different versions of OMS to a common and updated platform; and
- replacement of CitiPower's SCADA system with the same platform as that used by Powercor Australia.

The alignment of the GIS and OMS was delayed by CitiPower and Powercor Australia's primary service provider. Specifically, it was delayed due to the following:

- the structure, resourcing and management of the service provider's offshore development program;
- underestimation of the complexity of the project by the service provider; and
- underestimation of the level of testing required.

Alignment of the GIS and OMS has now been achieved and thus the replacement of CitiPower's SCADA system with the same platform as that used by Powercor Australia is in the implementation phase. The project is expected to go live in August 2010.

The installation of the DMS field devices is therefore expected to go ahead as proposed in the next regulatory control period.

9.11.3.3 Links to the Network Protection and Control Communications Strategy

The confidential minutes to CitiPower's CIC meeting on 1 June 2010 demonstrate that CitiPower continues to support the Network Protection and Control Communications Strategy 2009-2014:[790]

[789] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p132.

> *'Communication strategies and the smart grid initiative for both CP and PAL networks were outlined per the presentation. The Communication strategy includes programs to replace redundant technology (unable to be supported by manufacturers). The CIC endorsed the direction of the Communications and Control Strategy.'*

CitiPower maintains that each of its proposed projects link with the Network Protection and Control Communications Strategy 2009-2014.[791] This is shown in the material program templates for each of the relevant programs.[792] The linkages are also discussed in Table 9.14 below.

9.11.3.4 SCADA and network control programs proposed by CitiPower

As shown in Table 9.14 below, the programs proposed by CitiPower for the next regulatory control period justify forecast expenditure greater than the historical trend.

Program	Explanation and link to Network Protection and Control Communications Strategy 2009–2014
Installation of DMS field devices	Refer **Executive Summary** and **section 4** of the Network Protection and Control Communications Strategy 2009-2014**.** Installation of DMS field devices (coupled with the DMS) will allow network events to be modelled so that CitiPower can plan operational switching requirements that provide the best network performance and reliability. This is important given there will be an increased need to have a real time operational view of the network's condition in the next regulatory control period, for example, due to expected increases in the number of small and large embedded generators. The increasing amount of bi-directional power flows when embedded generators connect to the network leads to increasing complexity in ensuring the safe and reliable operation of the network. CitiPower's proposed program of installing DMS field devices is also required to maintain reliability of a network that is experiencing increasing utilisation levels and increased levels of embedded generation. The program will also allow CitiPower to have full control and knowledge of the distribution network, allowing CitiPower to avoid any increases in potential health and safety incidents. If the AER's Draft Determination was affirmed, however, CitiPower would not be able to maintain reliability and would not have full control and knowledge of the distribution network. This could give rise to potential health and safety incidents.
New fibre allowance[793]	Refer to **section 4(a)i** of the Network Protection and Control Communications Strategy 2009-2014. CitiPower is proposing SCADA and network control capex in the next regulatory period to establish fibre to all zone substations.[794] As noted in the Network Protection and Control Communications Strategy 2009–2014, fibre to all zone substations is required to ensure that the minimum bandwidth requirements necessary to take advantage of proposed increasing functionality of digital devices (including relays, meters and controllers) are met.[795] The existing copper supervisory cables use VF technology which is outdated and not compatible

[790] CitiPower, Minutes to the Capital Investment Committee meeting, 1 June 2010 (Attachment 168 to this Revised Regulatory Proposal), p2.
[791] Attachment P0030 to the Initial Regulatory Proposal.
[792] See material program templates provided to the AER by email on 9 March 2010 and material program templates included in Attachment 157 to this Revised Regulatory Proposal.
[793] See document titled 'CP 168 – New fibre allowance' (provided to the AER by email on 9 March 2010) and material program template 'New fibre allowance' (included in Attachment 157 to this Revised Regulatory Proposal).
[794] See material program template 'New fibre allowance' (included in Attachment 157 to this Revised Regulatory Proposal).
[795] CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment C0030 to the Initial Regulatory Proposal), p5.

	with the Ethernet protocols and modern equipment functionality and bandwidth requirements. The copper cables also limit the distance and speed that digital signals can be sent. Upgrading to fibre optics addresses these limitations including in relation to the distance or speed of data transfer. The need to replace the copper supervisory cables with optical fibre cables is set out in the Network Protection and Control Communications Strategy 2009-2014.[796] In summary, it is prudent to replace the copper supervisory system, and the benefits of fibre optics include: • enabling the deployment of modern relays when replacing protection schemes; • providing communication bandwidth for modern protocols; • facilitating, through modern equipment, the collection of data from stations; • facilitating, the implementation of security monitoring systems; • providing enhanced SCADA performance and increased data capture; and • enabling field workers to access to corporate networks at stations. The proposed program will allow CitiPower to maintain reliability and security of the protection interface between zone substations and transmission connection points. The program will also allow SP AusNet to complete the refurbishment of the Richmond terminal station and WMTS. The program will ensure compliance with clause 100.4 of the Electricity System Code (in relation to protection co-ordination). Without the proposed program, CitiPower would be unable to support the completion of SP AusNet's refurbishment of Richmond terminal station and WMTS. CitiPower would also be unable to maintain compliance with the protection co-ordination requirements of the Electricity System Code.
Ethernet roll-out and RTU conversions to DNP3.0[797]	Refer to **sections 4(a)i**, **4(a)v** and **4(c)** of the Network Protection and Control Communications Strategy 2009-2014. CitiPower is also proposing to rollout Ethernet into the zone substations and establish Ethernet connectivity in the next regulatory control period.[798] Zone substation Ethernet connectivity will facilitate integration of advanced protection and control technologies and allow migration to IP-based communications.[799] The rollout is to commence in 2010 and to be completed by the end of 2014.[800] The proposed program will maintain reliability by replacing equipment approaching the end of its life. It will also ensure that the risks of possible human error incidents due to delayed and inadequate data being communicated do not increase in the next regulatory control period. CitiPower considers that the program will ensure compliance with its 'good asset management' obligations in clause 3 of the Distribution Code.
Installation of Ethernet Programmable Logic Controllers (PLC) at indoor distribution substations[801]	Refer **sections 4(b)i and 4(b)ii** of the Network Protection and Control Communications Strategy 2009-2014. Existing distribution substations in the CBD and inner urban areas have an existing range of remote monitoring and control equipment including monitoring default indicators and full remove control and monitoring of switches. This ongoing program involves improving the existing remote switching flexibility of the network, as well as improving load collection capabilities in areas that may be highly loaded, or where remote switching lends itself to improved outage response and customer reliability. The introduction of

[796] CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment C0030 to the Initial Regulatory Proposal), pp7-8 (section 4(a)(i)).
[797] See document titled 'C168 – Ethernet rollout and RTU Conversions to DNP' (provided to the AER by email on 9 March 2010) and material program template 'CitiPower Ethernet rollout and RTU Conversions to DNP' (included in Attachment 157 to this Revised Regulatory Proposal).
[798] CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp10-1.
[799] CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), p10.
[800] CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), p11.
[801] See document titled 'CP 168 – install ethernert at indoor SS ' (provided to the AER by email on 9 March 2010) and material program template 'Install Ethernet PLC at existing indoor distribution substations' (included in Attachment 157 to this Revised Regulatory Proposal).

	DMS will enable this data to be readily captured by operational staff who can action this data as appropriate. Consistent with the Network Protection and Control Communications Strategy 2009-2014,[802] CitiPower is proposing works at seven sites per annum in the next regulatory control period. CitiPower will install a standard T200 switch controller Intelligent Electronic Device (IED), otherwise known as Programmable Logic Controller (PLC)) in various distribution substations. It is becoming increasingly difficult to access and manually switch distribution feeders in a timely manner. CitiPower's proposed program means that there will be no degradation in fault response times as a result of this. Without the proposed program, the increased difficulty of accessing and manually switching distribution feeders in a timely manner would mean that CitiPower would experience extended fault response times.
Installation of IEC61850 communications[803]	Refer to **section 4(c)** of the Network Protection and Control Communications Strategy 2009–2014. The new standard for protection relay communications is IEC61850. This communications protocol allows peer to peer communications between devices as well as SCADA communications and relay remote access and event reporting. This program involves CitiPower implementing communications around this new protocol standard and deploying suitable Ethernet systems to ensure backup capability within the zone substations. This includes dual Ethernet switches for redundancy and network servers that can manage and store the data from the relays for presentation to users. CitiPower expects to migrate to IEC61850 within the next 10 to 15 years, and thus consistent with its Network Protection and Control Communications Strategy 2009-2014,[804]. CitiPower is proposing to implement communications around this new protocol standard and deploying suitable Ethernet systems to ensure back-up capability within the substations. Going forward, the move to IEC61850 will allow CitiPower to maintain reliability and security of its network by ensuring effective communication with modern digital protection equipment. It will also ensure CitiPower is compliant with its 'good asset management' obligations under clause 3 of the Distribution Code. Without the prototyping and testing of IEC61850-enabled systems in the next regulatory control period, CitiPower would be unable to effectively migrate to IEC 61850 as contemplated in the Network Protection and Control Communications Strategy 2009-2014.

Table 9.14 Key SCADA and network control programs included in CitiPower's Revised Regulatory Proposal

While it is difficult to quantify the benefits likely to result from CitiPower's proposed SCADA and network control capex in the next regulatory control period, broadly, the benefits can be summarised as follows:

- improved data for making operational decisions (e.g. information regarding outages, voltage control, plant and equipment availability, service conditions, operational planning);
- improved data for making network planning decisions (e.g. information regarding network load and voltage modelling, contingency scenarios);
- improved data for condition monitoring assessments;
- better security of network sites;
- improved access to data for field technicians working at zone substations;

[802] CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment C0030 to the Initial Regulatory Proposal), pp14-5 (section 4(b)i and 4(b)ii).
[803] See document titled 'Installation of IEC61850 communications' (provided to the AER by email on 9 March 2010).
[804] CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp6, 17-9 (section 4(c)).

- improved ability to analyse network faults; and
- better ability to manage the network in relation to the uptake of household generation and electric vehicles, by having access to real time network loading where currently none exists.

Each of these benefits will allow CitiPower to maintain reliability and performance of the network and justify the SCADA and network control capex proposed by CitiPower in the next regulatory control period.

9.11.3.5 CitiPower Revised Regulatory Proposal

The SCADA and network control capex forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 9.15 below.

	$'000 (real 2010)					
Expenditure category	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
SCADA/Network control	4,793	4,490	4,729	4,830	4,912	**23,754**

Table 9.15 SCADA and network control capex forecasts included in CitiPower's Revised Regulatory Proposal

9.12 Non-network capex

9.12.1 CitiPower's Initial Regulatory Proposal

The non-network capex included in CitiPower's Initial Regulatory Proposal falls into two subcategories:[805]

- IT (supporting the management of distribution assets, relating to customer service systems, to corporate systems and underlying IT support architecture); and
- 'other' (including general equipment, motor vehicles, office furniture and property).

The IT subcategory can be further broken down into 'general' IT capex and capex related to projects designed to make use of some of the functions inherent in the AMI meters that would not have been initiated (and thus whose costs would not be recoverable) as part of the AMI roll-out. These projects are referred to as 'AMI leveraged projects'.

The AMI leveraged projects proposed by CitiPower (as joint projects with Powercor Australia) were the subject of a cost benefit analysis performed by PwC. They were found to give rise to significant benefits across the two businesses.[806]

CitiPower set out its approach to forecasting IT capex in its Initial Regulatory Proposal.[807] CitiPower provided to the AER material projects templates setting out details of its forecasts in respect of one major general IT project (the replacement of its CIS), as well as a material projects template in respect of the AMI leveraged projects.[808]

[805] Initial Regulatory Proposal, pp136-7.
[806] PwC, CitiPower and Powercor, AMI leveraged projects, An assessment of the justifiable need for investment in additional AMI capabilities, October 2009 (Attachment P0036 to the Initial Regulatory Proposal).
[807] Initial Regulatory Proposal, pp137-139.
[808] Initial Regulatory Proposal, pp415-21.

CitiPower also provided to the AER CHED Services' IT Strategic Plan 2010 - 2015,[809] together with an independent review of that plan by Gartner Inc.[810] Subsequent to the Initial Regulatory Proposal, CitiPower provided additional information relating to general IT capex in CitiPower's Response to the AER's Capex Guideline paper.[811] On 26 February 2010, following a meeting with the AER on 10 February 2010, CitiPower provided to the AER a written response to its additional queries, including details of CitiPower's IT procedure on decommissioning of assets and of the build up of the replacement of the CIS and the governance processes for a number of IT projects.

9.12.2 AER's Draft Determination

In its Draft Determination, the AER observed that Victorian DNSPs' actual capex tends to follow a gradually increasing trend.[812]

The AER's findings regarding non-network – IT (general) capex, non-network – IT (AMI leveraged projects) capex and non-network – other capex are set out below.

9.12.2.1 Non-network – IT (general)

The AER concluded that CitiPower had underspent relative to the ESCV allowance in the current regulatory control period because it considered it was efficient to do so.[813]

The AER (somewhat inconsistently) also stated that each DNSP's IT activities in the current regulatory control period have been limited by operational capabilities and the amount of IT changes able to be tolerated by the DNSP. It sought to illustrate this by reference to the deferral by CitiPower of the replacement of its CIS as a result of the mandated AMI roll-out.[814]

The AER agreed with Nuttall Consulting that CitiPower does not have 'agile' IT architecture supporting its business operations and service delivery and that this absence of 'agile' IT environments will hinder CitiPower's ability to complete its proposed IT projects in the next regulatory control period. The AER further observed that the Victorian DNSPs' IT strategies do not discuss how their proposed IT investments would allow them to better respond in future to external events such as the mandated AMI roll-out.[815]

Accordingly, the AER concluded that '*the DNSPs will likely defer projects or adopt alternative projects in the forthcoming regulatory control period*' and accepted Nuttall Consulting's recommendation of reducing the general IT capex forecast by spreading CitiPower's IT capex forecast for 2011-13 evenly across 2011-15.[816]

[809] Attachment P0010 to the Initial Regulatory Proposal.
[810] Attachment P0012 to the Initial Regulatory Proposal.
[811] The response was provided to the AER on 11 January 2010.
[812] AER, Draft Determination, p418.
[813] AER, Draft Determination, p420.
[814] AER, Draft Determination, p421.
[815] AER, Draft Determination, p421.
[816] AER, Draft Determination, p422.

9.12.2.2 Non-network – IT (AMI leveraged projects)

The AER accepted the conclusion reached by Nuttall Consulting, as a result of its investigation of the AMI leveraged projects, that there was no evidence of 'double counting' in Victorian DNSPs' non-network - IT capex of the AMI roll-out costs to be recovered by those DNSPs in accordance with the AER's AMI determination made in 2009.[817] Nonetheless, the AER did not allow any capex on AMI leveraged projects proposed by any Victorian DNSP.

The AER rejected CitiPower's proposed capex on AMI leveraged projects for the following reasons:

- the AER rejected the probative value of the PwC cost benefit analysis of the AMI leveraged projects on the basis that it was prepared externally rather than internally;[818]
- the AER considered that the S factor scheme provides financial incentives to CitiPower to implement projects (such as the AMI leveraged projects) that achieve reliability benefits;[819] and
- the AER also concluded that the implementation of enhanced load shedding capabilities may defer some network reinforcement projects and thus the DNSPs' reinforcement capex amounts should allow for implementation of enhanced load shedding capabilities.[820]

9.12.2.3 Non-network - other

The AER accepted CitiPower's proposed capex for the non-network – other capex category on the basis that the proposed capex is consistent with a continuation of the historical expenditure trend.[821]

9.12.3 CitiPower's response to the AER's Draft Determination

9.12.3.1 Summary

CitiPower maintains that its proposed non-network – IT capex forecasts reasonably reflect the capex criteria.

CitiPower's expenditure in the current regulatory control period has been reduced relative to the ESCV's allowance in the 2006-10 EDPR as a result of the mandated AMI roll-out. CitiPower does not consider that an event such as the AMI roll-out will occur in the next regulatory control period such that CitiPower's non-network – IT capex should be constrained to the levels of its actual expenditure in the current regulatory control period. CitiPower rejects Nuttall Consulting's assertion that its IT systems are not 'agile' and submits that its proposed expenditure is required to ensure that its systems will remain 'agile' in the next regulatory control period.

The AER cannot discount the evidentiary value of the external cost benefit analysis CitiPower obtained from PwC in respect of its AMI leveraged project on the basis that it is

[817] AER, Draft Determination, p423.
[818] AER, Draft Determination, p423.
[819] AER, Draft Determination, p423.
[820] AER, Draft Determination, p423.
[821] AER, Draft Determination, p432.

not an internal assessment. As part of this Revised Regulatory Proposal, CitiPower has removed one of the components from the AMI leveraged project that is able to be recovered through the S-factor scheme. CitiPower also rejects the AER's proposition that reinforcement capex deferrals would contribute to the funding of AMI leveraged projects.

CitiPower does not contest the AER's Draft Determination with respect to non-network – other capex.

For the reasons outlined in the 'General issues' section above, CitiPower considers that the AER should use 2009 actual data in its trend analysis. CitiPower notes that, as demonstrated by Figures 9.5 and 9.6 below, when 2009 actual data is incorporated into the analysis, the AER's conclusion that CitiPower's actual non-network capex follows a gradually increasing trend is less compelling.

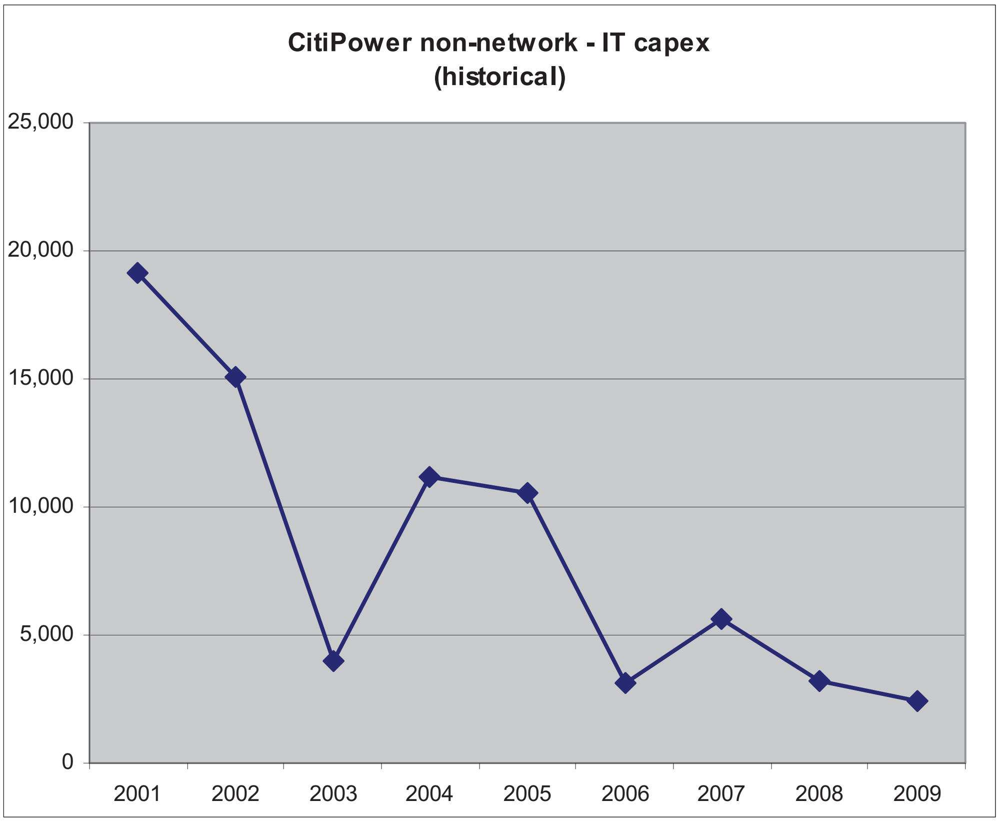


Figure 9.5 CitiPower's historical non-network - IT capex

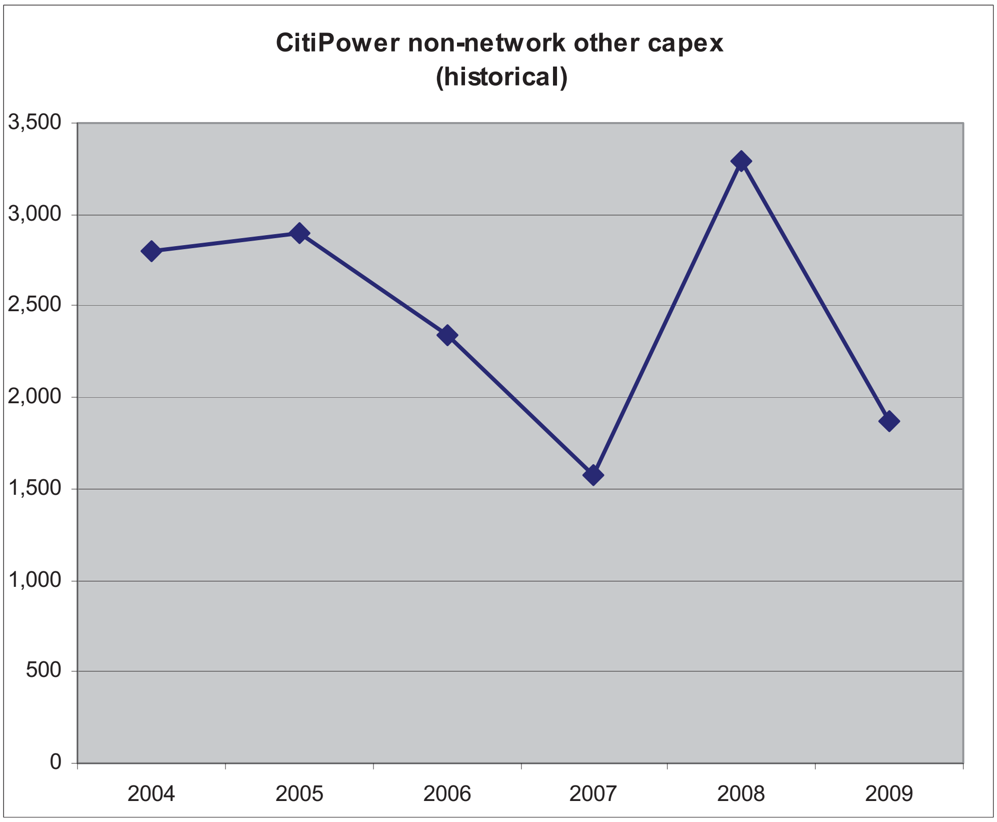


Figure 9.6 CitiPower's historical non-network - other capex

9.12.3.2 Non-network – IT (general)

Contrary to the AER's suggestion that CitiPower underspent on IT (relative to the ESCV allowance) in the current regulatory control period because it was efficient to do so, CitiPower reiterates that CitiPower underspent because it directed IT resources to the implementation of the mandated AMI rollout. Thus, the decision to reduce expenditure on non-AMI IT was not based on reasons of efficiency, but on the need to respond to new legal obligations emerging in the course of the regulatory control period. The AER recognised as much, in stating that each DNSP's IT activities in the current regulatory control period have been limited by operational capabilities and the amount of IT changes able to be tolerated by the DNSP.

As discussed above, the AER rejected CitiPower's proposed non-network - IT (general) capex because it concluded that '*the DNSPs will likely defer projects or adopt alternative projects in the forthcoming regulatory control period*'.[822] While the AER's reasoning process is not made wholly explicit in the Draft Determination, the AER would appear to have reached this conclusion because:

- the Victorian DNSPs' IT activities in the current regulatory control period have been limited by operational capabilities and the amount of IT changes able to be tolerated by the DNSPs, the AER's inference being that CitiPower's proposed general IT projects for the 2011-15 period are likely to be similarly constrained in this period; and

[822] AER, Draft Determination, p422.

- the asserted lack of 'agility' of the Victorian DNSPs' IT architecture supporting its business operations and service delivery will hinder CitiPower's ability to complete its proposed IT projects in the next regulatory control period.

As noted above, CitiPower agrees that its IT activities in the current regulatory control period have been reduced from those in the previous regulatory control period, as a result of the mandated AMI roll-out.[823] However, CitiPower does not accept the AER's inference that this means it will likely defer or modify its proposed non-network - IT projects in the 2011-15 period.

In making this inference, the AER has assumed that an event akin to the mandated AMI roll-out will occur in the next regulatory control period. There is no basis for concluding that such an event will occur in the next regulatory control period.

The task with which the AER is charged is to assess whether CitiPower's non-network - IT capex reasonably reflects the efficient and prudent costs required to achieve the capex objectives. In making this assessment, the AER must do so on the basis of a reasonable expectation of future external events.

To assume that an event akin to the mandated AMI roll-out will occur in the next regulatory control period, and thus to reduce CitiPower's proposed non-network - IT capex because of the limitations such an event would impose on its operational capabilities, is not reasonable. Regulatory change necessitating an IT project of the size and scale of the AMI roll-out is an exceptional event. There is no reason to think (and certainly no evidence on which to reach a conclusion) that regulatory changes necessitating an IT project of the size and scale of the AMI roll-out will occur in the next regulatory control period.

It is only where the AER determines that there is a realistic expectation of a future event necessitating an IT project of a size and scale similar to that necessitated by the AMI roll-out, in circumstances where the resultant costs will not be recovered through charges for standard control services, that the deferral of IT projects by CitiPower in the current regulatory control period as a result of the mandated AMI roll-out provides a basis for concluding that '*the DNSPs will likely defer projects or adopt alternative projects in the forthcoming regulatory control period*'. CitiPower maintains that there is little possibility of such a future event.

CitiPower rejects Nuttall Consulting's assertion that its IT systems are not 'agile'. This is for a number of reasons.

The detail of Nuttall Consulting's analysis is not DNSP specific.[824] As a result, Nuttall Consulting's findings are gross generalisations and do not take into account the specific circumstances of CitiPower.

[823] The most significant example of this was the deferral of the replacement of the CIS. As noted in the material projects table relating to this project and the slides provided to the AER on 26 February 2010, the replacement of the CIS was deferred because the introduction of AMI meant that changing billing systems could potentially increase the risks of delivering the AMI project. The deferral was not the result of limitations on CitiPower's IT capabilities or its ability to accommodate IT change.
[824] Nuttall Consulting, Report – Capital Expenditure*,* 4 June 2010, pp74-81.

In discussing the concept of agility in its report, Nuttall Consulting provides examples of the kinds of IT infrastructure it considers to be 'agile'.[825] A number of these technology approaches are already within use across CitiPower's business. CitiPower has, for instance (as Nuttall Consulting recognises in its report), used Server Virtualisation since 2004.[826] Server Virtualisation delivers each of the attributes described by Nuttall Consulting in its report[827] being high availability, enhanced disaster recovery, portability and live migration.

Further, many systems commonly considered to be 'agile' systems are used by CitiPower. For example:

- CitiPower has had 'open systems' since 1999;
- it uses commercial 'off the shelf' software rather than customer software; and
- CitiPower's IT systems already have identity management to enable many users across multiple systems.

CitiPower ensures its systems are agile by using leading technology platform providers. For example, business applications are supplied by SAP, GE Energy and Microsoft. CitiPower's DBMS facilities are by Oracle, SQL Server and its infrastructure is by Hitachi Data Systems, Hewlett-Packard, CISCO Systems, Sun and Toshiba. CitiPower's IT services are sourced from a number of different providers to maximise value, demand and skill flexibility, including Computer Sciences Corporation Australia, WiPro IT Business, General Electric Energy, DWS Advance Business Solutions, SMS Management & Technology and Logica Australia.[828]

CitiPower ensures its systems are agile by using leading technology platform providers.

CitiPower also notes that it has demonstrated repeatedly over the past 15 years its ability to manage and execute major IT projects including those necessitated by the SECV privatisation, the introduction of full retail contestability in Victoria, the merger with Powercor Australia and the AMI roll-out.

If AMI IT expenditure is added to (standard control) non-network – IT capex, the amounts invested by CitiPower and Powercor Australia exceed the ESCV allowance for both businesses. In nominal terms, CitiPower and Powercor Australia spent $16m, $28m and $45m in the period 2006-08. The overall expenditure by CitiPower on IT systems in the current regulatory control period therefore demonstrates that its systems are sufficiently 'agile' to accommodate a significant degree of IT development.

While the AER used the deferral of the replacement of the CIS as an example of CitiPower deferring capex because of limitations on its IT capabilities and the amount of IT change that can be accommodated by CitiPower,[829] this deferral was not for these reasons. Rather, as noted in the material projects template relating to the CIS and the slides provided to the

[825] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp78-81.
[826] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p213.
[827] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p79.
[828] More details regarding CitiPower's IT service providers are set out in Attachment 173 to this Revised Regulatory Proposal.
[829] AER, Draft Determination, p421.

AER on 26 February 2010,[830] the replacement of the CIS was deferred because the introduction of AMI meant that changing billing systems could potentially increase the risks of delivering the AMI project.

CitiPower observes that the implementation of a new billing system is a highly complex major project. It is necessary to establish clearly defined requirements at the project initiation stage and any variation to the project must be minimised during the life of the project to reduce the risk of increased cost and time delays. In the absence of absolute certainty of the emerging billing requirements (e.g. TOU Tariffs) an AMI environment introduced an unacceptable level of risk that any new billing system would quickly become redundant. This would have inflated the total cost of the project implementation. Instead, CitiPower made tactical enhancements to the existing billing system to extend its life to the end of the AMI rollout. The replacement program is scheduled to ensure that all AMI requirements can be identified in the new billing systems application. Accordingly, it is clear that the deferral was not the result of limitations on CitiPower's IT capabilities or its ability to accommodate IT change.

In this regard, CitiPower notes that the AER's Draft Determination is inconsistent with the AER's decision to allow capex to ETSA for the CIS.[831] The replacement is a joint project between ETSA, CitiPower and Powercor Australia. The expert engaged by the AER in ETSA's price review process, PB, concluded that ETSA's proposed IT capex was prudent and efficient.[832] PB noted that replacement of the CIS was required because the IT platform support has been extended as far as possible because of the discontinued vendor systems and that ETSA's cost sharing with CitiPower and Powercor Australia was an efficient way to manage the replacement.[833]

The AER noted in its Draft Determination that CitiPower and Powercor Australia had *'already deferred'* the replacement of the CIS from the current regulatory control period to 2014 in the next regulatory control period.[834] The AER appears to be implying that CitiPower and Powercor Australia may defer the project again. However, the project cannot be further delayed. This is because:

- the vendor of the existing CIS (CIS-OV) ceased business in 1995. The asset was purchased by Logica but immediately withdrawn from the market. This means that there is no committed support for the product;
- all vendor initiated development of CIS-OV ceased in 2003. As a consequence, no product maintenance or enhancements are initiated by the vendor;

[830] CitiPower and Powercor Australia, Project Proposal CIS Replacement 2013 – 2015, May 2009 (provided to the AER by email on 26 February 2010), slide 3.
[831] AER, South Australian Draft Determination, p171; AER, South Australian Distribution Determination, pp105-6.
[832] PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to Jun 2015, November 2009 (Attachment 135 to this Revised Regulatory Proposal), p100.
[833] PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to Jun 2015, November 2009 (Attachment 135 to this Revised Regulatory Proposal), p99. The CIS is one component of the 'FRC systems' referred to by PB. A general discussion of the FRC systems is included in a report by SMS Consulting (commissioned by ETSA), Strategic Scenarios Assessment, 25 February 2009, Attachment F.11 to ETSA's regulatory proposal (Attachment 107 to this Revised Regulatory Proposal).
[834] AER, Draft Determination, p421.

- by 2015, the CIS-OV will be 16 years old and well beyond its expected service life. The underlying technology supporting CIS-OV (Cobol, Powerbuilder & Tuxedo) will become obsolete; and
- CitiPower is one of the last remaining customers in the world using CIS-OV in this form.

As noted in the material projects template provided in the Initial Regulatory Proposal, the above means that the lack of ongoing support for the CIS-OV presents a risk to CitiPower as the stability of its system is likely to be impaired. Failure to update the system will also mean that the full benefits of AMI cannot be realised.

Against this background, the AER's rejection of CitiPower's non-network - IT capex including that required for replacement of the CIS is contrary and internally inconsistent. The AER rejects that capex, in part, on the (incorrect) basis that CitiPower's existing IT infrastructure is not 'agile'. But, in so doing, the AER does not fund CitiPower to implement the very IT projects, such as the replacement of the CIS, required if CitiPower is to maintain the agility of its IT infrastructure in 2011-15 and beyond.

CitiPower notes Nuttall Consulting's findings that, in light of the many unknowns in operating a DNSP business, an efficient DNSP would require agile IT architecture that would be able to readily accommodate a reasonable level of change even before a major capital investment is required.[835] Much of CitiPower's proposed capex is aimed at keeping systems 'agile' and avoiding technical and commercial obsolescence. For example, the proposed capex includes:

- the replacement of the CIS, which, as discussed in greater detail above is required to ensure the system remains 'agile';
- the replacement of a PABX system that is over 20 years old with VoIP and associated unified communication software, which provides one network for voice and data services and will result in improved customer service, optimise system availability and maximise business efficiency;
- growth and refreshment of SANS, archive backup and de-duplication technology and upgrade system monitoring systems;
- undertaking cyclical upgrades of Unix, Linux, Window Servers for capacity of maintenance at supported levels – migrating to Blade technology where supported;
- cyclical upgrades of Core Network Switches, LAN Switches, Firewalls, Remote Access (VPN, Citrix), Security Gateway Technology Systems (Firewalls, Reverse proxy, Internet & Email protection systems);
- cyclical upgrades of Identity Management, Antivirus, Anti Malware, AntiSpyware, Host Intrusion Prevention and Data loss prevention systems; and
- cyclical upgrades of desk top virtualisation, software packaging, operating systems and office productivity systems.

In contrast to the AER's comment that the Victorian DNSPs' IT strategies do not discuss how their proposed IT investments would allow them to better respond in future to external

[835] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p79.

events such as the mandated AMI roll-out,[836] CitiPower believes it has a proven record in responding to external events and changes. The IT Policies, IT Application Strategies, IT Sourcing Strategies, all contained in the Information Technology Strategic Plan 2010-15,[837] clearly set out strategies that have, and will continue to, enable the CitiPower to establish itself from the SECV, manage the introduction of the goods and services tax, deal with Y2K, develop systems for full retail contestability in Victoria and South Australia, and deal with multiple company mergers, divestures and purchases. In addition, CitiPower has made extensive investments in lessons learned and 'future proofing' to allow it to respond to ever increasing changes in the electricity sector and the technology arena.

Thus, CitiPower's proposed capex for each of the above projects should be considered prudent and efficient.

Upgrading infrastructure is also critical to managing increasing staff numbers, increasing security requirements, managing growing data volumes, constant monitoring (i.e. 24 hours, seven days a week) of systems and maintaining CitiPower's disaster recovery programs. Table 9.16 below demonstrates the growth in IT infrastructure since 2003, thus demonstrating the need for continued growth in IT infrastructure.

	2003	2004	2005	2006	2007	2008	2009	2010
Windows Servers	80	111	111	104	160	295	366	450
Unix / Linux Servers	25	35	38	32	38	53	84	90
Oracle Databases	55	125	140	160	177	193	260	298
SQL Databases	5	6	6	11	20	45	53	65
SAP Systems	5	6	10	14	17	13	19	24
LAN/WAN Devices			158	154	165	174	188	210
Security Devices	2	6	6	8	8	16	28	34
Disk Terabytes	10	20	28	45	53	68	90	210

Table 9.16 Growth in CitiPower and Powercor Australia's IT infrastructure

CitiPower does not consider that an amount based on historical non-network – IT capex will provide sufficient capex in the next regulatory control period to allow CitiPower to meet the capex objectives. As the AER itself acknowledged, given the variability of capex amounts in this category, the historic trend cannot completely determine future requirements.[838] CitiPower requests that the AER actively engage in considering the material before it (in both the Initial Regulatory Proposal and this Revised Regulatory Proposal). If it does so, the AER should be satisfied that the proposed expenditure is prudent and efficient and reasonably reflects the capex criteria.

[836] AER, Draft Determination, p421.
[837] Attachment P0010 to the Initial Regulatory Proposal.
[838] AER, Draft Determination, p419.

9.12.3.3 Non-network – IT (AMI leveraged projects)

As noted in the 'General issues' section above, the AER cannot discount the evidentiary value of the external cost benefit analysis CitiPower obtained from PwC in respect of the AMI leveraged projects on the basis that it is not an internal assessment of the projects. The PwC report provides an independent expert opinion that identifies the significant benefits of the AMI leveraged projects for CitiPower and Powercor Australia's customers and concludes that the projects are justified on the basis of a cost benefit analysis.[839] There is no foundation for the AER's conclusion that the probative value of this PwC report is reduced by reason of the fact that it contains an independent expert analysis of the costs and benefits of the relevant projects rather than an internal assessment. To the contrary, the fact that the PwC report is an **independent** and **expert** opinion, rather than an internal opinion, if anything, increases its probative value.

Contrary to the AER's conclusion in the Draft Determination, CitiPower cannot recover its costs for the AMI leveraged projects through the S factor scheme. CitiPower acknowledges that **one** of the AMI leveraged projects (specifically, automatic outage notification) may generate a STPIS saving. CitiPower has therefore removed this particular project in preparing its capex forecasts in this Revised Regulatory Proposal. CitiPower notes that, even if the automatic outage notification is removed from the analysis, PwC's review indicates that the AMI leveraged projects give rise to an expected benefit of $29,863,000.[840] The costs of the remaining AMI leveraged projects proposed by CitiPower (set out in Table 9.17 below), however, will not be funded through the S factor.

Additional capability	Description	STPIS implication
Enhanced load shedding capability	Using the AMI meters' functionality to enable more granular emergency load shedding by allowing a 'bottom-up' choice of customer load shed, in order to reduce the cost of unserved energy from necessary load sheds.	None. The enhanced load shedding functionality is intended for use during times where the DNSP is directed to shed load by AEMO. Load shedding is excluded from the STPIS.
Enhanced powerflow analysis – near real time network data	Leveraging data collected by the AMI meters to provide forecasting and scheduling information and simulation capability to improve network management and asset optimisation. This functionality will be particularly important in the context of increasing embedded or distributed generation sources.	None. The additional functionality is intended to assist network planners in determining when and where to augment the network.
Quality of supply event recording –	Utilising the AMI meters' Quality of	None. Quality of supply

839 PwC, CitiPower and Powercor, AMI leveraged projects, An assessment of the justifiable need for investment in additional AMI capabilities, October 2009 (Attachment P0036 to the Initial Regulatory Proposal).
840 PwC, CitiPower and Powercor, AMI leveraged projects, An assessment of the justifiable need for investment in additional AMI capabilities, October 2009 (Attachment P0036 to the Initial Regulatory Proposal), p49.

proactive voltage compliant analysis	Supply (QoS) recording to allow improved analysis, network management and customer service. This will allow the businesses to adequately monitor quality of supply compliance.	measures are not part of the STPIS.
Customer load controls	Enabling implementation of agreed load limits, including emergency supply constraints.	None. The customer load control functionality is intended for use during times where the DNSP is directed to shed load by AEMO. Load shedding events are excluded from the STPIS.
Consumption profiling	An analytical capability, whereby supply data may be quickly and easily analysed to establish consumer profiles for network planning and forecasting. This ability to understand consumer profiles will enhance the load shedding capability.	None. Consumption profiling will be used by network planners to improve decisions with respect to when and where to augment the network. It will also assist in tariff design.

Table 9.17 AMI leveraged projects proposed by CitiPower

CitiPower rejects the proposition that reinforcement capex deferrals would contribute to the funding of the AMI leveraged projects.

The AER reasoned that, as the AMI leveraged projects would enable reinforcement capex deferrals, a portion of the reinforcement capex allowed by the AER in the Draft Determination for the 2011-15 period could be redirected to funding the AMI leveraged projects in that period. However, the AER's reasoning assumes that any reinforcement capex savings associated with the AMI leveraged projects would be realised in the 2011-15 regulatory control period. This assumption is incorrect.

Any reinforcement capex savings associated with the AMI leveraged projects would be realised only after completion of those projects. The AMI leveraged projects are only scheduled for completion in 2015.[841] This eliminates the potential for any reinforcement capex deferral benefit to arise in the period 2011-15 and, thus also, the potential for such a benefit to be used to (partially) fund the implementation of the AMI leveraged projects in that period.

Further, the AER would be expected to take into account capital deferral benefits likely to be realised in the 2016-20 period as a result of the AMI leveraged projects upfront, i.e. it would not allow reinforcement capex that could be deferred through the AMI leveraged projects in the period 2016-20. As a consequence, the benefit of any network reinforcement deferral will be passed immediately through to customers without CitiPower obtaining any

[841] PwC, CitiPower and Powercor, AMI leveraged projects, An assessment of the justifiable need for investment in additional AMI capabilities, October 2009 (Attachment P0036 to the Initial Regulatory Proposal), p15 (Table 2.3).

share of those benefits that could be directed towards (partially) funding the AMI leveraged projects.

9.12.3.4 Non-network – other

CitiPower does not contest the AER's Draft Determination with respect to non-network – other capex.

9.12.4 CitiPower's Revised Regulatory Proposal

The non-network capex forecasts included in CitiPower's Revised Regulatory Proposal are set out in Table 9.18 below.

	$'000 (real 2010)					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Non-Network Assets - IT	9,920	9,045	8,924	14,018	11,123	**53,029**
Non-Network Assets - Other	3,108	3,401	3,219	3,262	3,294	**16,284**
Non-Network Assets - Total	**13,028**	**12,445**	**12,143**	**17,280**	**14,417**	**69,313**

Table 9.18 Non-network capex forecasts included in CitiPower's Revised Regulatory Proposal

9.13 CitiPower's Revised Regulatory Proposal

The total forecast capex included in CitiPower's Revised Regulatory Proposal is set out in Table 9.19. The key assumptions which underlie the proposed capex as set out and included in CitiPower's building block proposal are listed in Appendix 1.1 to this Revised Regulatory Proposal.

	$'000 (real 2010)					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Reinforcement	60,673	66,586	81,668	66,181	47,378	322,486
Gross new customer connections	60,022	62,278	62,577	64,203	66,150	315,231
Sub-total demand related	**120,696**	**128,864**	**144,245**	**130,384**	**113,528**	**637,717**
Reliability and quality maintained	46,132	50,777	52,043	56,656	60,766	266,374
Environmental, safety and legal	1,440	1,465	1,474	1,499	1,532	7,411
SCADA/Network Control	4,793	4,490	4,729	4,830	4,912	23,754
Sub-total network	**173,061**	**185,596**	**202,491**	**193,368**	**180,739**	**935,256**
Non-network - IT	9,920	9,045	8,924	14,018	11,123	53,029
Non-network - other	3,108	3,401	3,219	3,262	3,294	16,284

Sub-total non-network	**13,028**	**12,445**	**12,143**	**17,280**	**14,417**	**69,313**
Total gross capex	**186,089**	**198,042**	**214,634**	**210,648**	**195,156**	**1,004,569**
Less capital contributions	9,576	10,885	11,016	11,653	12,314	55,444
Total	**176,513**	**187,157**	**203,619**	**198,995**	**182,842**	**949,125**

Table 9.19 Total forecast capex included in CitiPower's Revised Regulatory Proposal

10. OPENING ASSET BASE

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 9 of the Draft Determination regarding CitiPower's opening asset base.

10.1 Summary of key points

CitiPower accepts the approach set out in the Draft Determination in relation to the opening RAB except for the AER's adjustment to account for the difference between estimated and actual disposals in 2005. CitiPower does not consider that the AER's adjustment to disposals is permitted by the Rules.

10.2 Rules requirements

Clause 6.4.3(a)(1) of the Rules provides that the indexation of the RAB is one of the building blocks to be used in calculating the ARR 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;
- schedule 6.2 of the Rules, which provides information on establishing the opening RAB for the next regulatory control period and rolling the RAB forward between years.

Clauses S6.2.1(c) and S6.2.1(e) of the Rules specify the adjustments that the AER must make when rolling forward the RAB to determine the opening RAB as at 1 January 2011. The only adjustments that the AER is permitted to make are those set out in these clauses.

10.3 CitiPower's Initial Regulatory Proposal

CitiPower provided as an attachment to its Initial Regulatory Proposal a Roll Forward Model setting out the roll forward of the RAB to 31 December 2010.[842]

Table 10.1 shows the roll forward of CitiPower's RAB to 31 December 2010 as set out in the Initial Regulatory Proposal.[843]

	$m (nominal)				
	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

[842] Roll Forward Model (Attachment 3 to the Initial Regulatory Proposal).
[843] Initial Regulatory Proposal, p294.

Table 10.1 Initial Regulatory Proposal - Roll forward of the RAB from 1 January 2006 to 31 December 2010

10.4 AER's Draft Determination

The AER's decision on CitiPower's opening RAB in the Draft Determination is set out in Table 10.2.[844]

	$m (2010)				
	2006	2007	2008	2009	2010
Opening RAB	1,176.8	1,194.1	1,197.6	1,206.5	1,233.5
Net capex	93.6	79.1	84.6	97.5	124.7
Depreciation	-76.3	-75.7	-75.6	-70.5	-72.0
Compound return on 2005 capex difference					0.4
Closing RAB	1,194.1	1,197.6	1,206.5	1,233.5	1,286.5
Difference from proposed RAB					-4.5

Table 10.2: Draft Determination - Roll forward of the RAB from 1 January 2006 to 31 December 2010

The AER's Roll Forward Model calculates 2005 actual and estimated net capex by subtracting 2005 actual and estimated disposals. As a result, the AER has made an adjustment to the opening value of the RAB to account for the difference between estimated and actual disposals in 2005.

The AER's Roll Forward Model also applies the cash value of proceeds from the sale of assets for disposals whereas CitiPower proposed applying the book value of disposals.[845]

In calculating the roll forward of the RAB from 1 January 2011 to 31 December 2015, the AER has accepted CitiPower's forecast in its Initial Regulatory Proposal of zero disposals over the period.

10.5 CitiPower's response to the AER's Draft Determination

CitiPower accepts the approach set out in the Draft Determination in relation to the opening RAB, except for the AER's adjustment to the value of 2005 disposals. CitiPower considers that the AER does not have any power under the Rules to make this adjustment.

Clause S6.2.1(e)(6) permits the AER, in determining the opening RAB value for 2011-15, to make adjustments to remove the disposal value of any asset disposed of in the previous regulatory control period, i.e. in 2006-10. It does not empower the AER to make adjustments for disposals occurring prior to the previous regulatory control period, e.g. in 2005.

Clause S6.2.1(c)(2) contains a specific power for the AER to make adjustments for the difference between estimated and actual capex in *any* previous regulatory control period, i.e. it would allow the AER to make such adjustments for the difference between estimated and actual capex in 2005. The Rules do not contain any similar power to make adjustments for

[844] AER, Draft Determination, p455.
[845] AER, Draft Determination, p444.

the difference between estimated and actual disposals in *any* previous regulatory control period, e.g. in 2005.

An adjustment to account for disposals is not permitted by the Rules as part of making the adjustment for the difference between estimated and actual capex in *any* previous regulatory control period under clause S6.2.1(c)(2). To construe the power conferred by clause S6.2.1(c)(2) in this manner would be erroneous. This is because the existence of clause S6.2.1(e)(6), which specifically provides for disposals and confers a power to make an adjustment to account for the disposal value of any asset that was disposed of in the previous regulatory control period (i.e. 2006-10), indicates that clauses S6.2.1(c)(2) and S6.2.1(e)(3) do not confer such a power.

This express power in relation to disposals in the 2006-10 period, and the absence of any similar power in relation to disposals in any prior period, confirms that:

- a power to make an adjustment for 2005 disposals could not have been intended to be within the scope of the capex adjustment permitted by clause S6.2.1(c)(2); and
- accordingly, the AER does not have any power to make an adjustment to account for the difference between estimated and actual disposals in 2005.

CitiPower accepts the AER's approach of applying the cash value of proceeds from the sale of assets for disposals instead of the book value of disposals. It also accepts the AER's decision that forecast disposals for the 2011-15 period are zero.

10.6 CitiPower's Revised Regulatory Proposal

CitiPower amends its Initial Regulatory Proposal to adopt the approach set out in the Draft Determination in relation to the opening RAB, except for the AER's adjustment to the value of disposals in 2005. CitiPower considers that no adjustment should be made to account for the difference between estimated and actual disposals in 2005.

CitiPower's calculation of the opening RAB is set out in Table 10.3.

	$m (nominal)				
	2006	2007	2008	2009	2010
Opening RAB	1,015.1	1,061.1	1,106.2	1,135.2	1,218.0
Net capex	83.6	73.6	79.6	96.2	125.8
Disposals	0.5	0.5	0.0	0.2	-
Depreciation	67.8	69.9	71.2	69.6	72.0
Indexation of RAB	30.7	41.8	20.6	56.4	15.4
Closing RAB	1,061.1	1,106.2	1,135.2	1,218.0	1,287.1

Table 10.3 Roll forward of the RAB from 1 January 2006 to 31 December 2010

CitiPower's calculation of the roll forward of the RAB from 1 January 2011 to 31 December 2015 is set out in Table 10.4.

	$m (nominal)				
	2011	2012	2013	2014	2015
Opening RAB	1,287.6	1,443.2	1,608.7	1,793.9	1,975.4
Net capex	190.3	204.2	227.9	228.4	215.3
Disposals	-	-	-	-	-
Depreciation	67.9	75.7	84.0	93.0	103.2
Indexation of RAB	33.1	37.1	41.3	46.1	50.8
Closing RAB	1,443.2	1,608.7	1,793.9	1,975.4	2,138.2

Table 10.4: Roll forward of the RAB from 1 January 2011 to 31 December 2015

11. DEPRECIATION

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 10 of the Draft Determination regarding depreciation.

11.1 Summary of key points

CitiPower accepts the approach set out in the Draft Determination in relation to depreciation, except for the minor adjustments and corrections to the AER's calculations that are set out in CitiPower's Roll Forward Model.

11.2 Rules requirements

Depreciation must be calculated in accordance with clause 6.5.5 of the Rules, which provides:

'(a) *The depreciation for each* regulatory year*:*

(1) *must be calculated on the value of the assets as included in the regulatory asset base, as at the beginning of that* regulatory year*, for the relevant* distribution system*; and*

(2) *must be calculated:*

(i) *providing such depreciation schedules conform with the requirements set out in paragraph (b), using the depreciation schedules for each asset or category of assets that are nominated in the relevant* Distribution Network Service Provider's building block proposal*; or*

(ii) *to the extent the depreciation schedules nominated in the provider's* building block proposal *do not so conform, using the depreciation schedules determined for that purpose by the* AER.

(b) The depreciation schedules referred to in paragraph (a) must conform to the following requirements:

(1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;

(2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant distribution system*) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant* distribution system*;*

(3) the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period *must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.'*

11.3 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower used the AER's Post Tax Revenue Model to calculate depreciation in accordance with the requirements of clause 6.5.5 of the Rules as follows:[846]

	$m (nominal)					
	2011	2012	2013	2014	2015	Total
Depreciation	33.2	36.7	40.2	44.2	49.3	203.5

Table 11.1 Initial Regulatory Proposal - Depreciation

This depreciation calculation was based on the following proposed asset lives:[847]

	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 11.2 Initial Regulatory Proposal - Asset lives (years)

11.4 AER's Draft Determination

In the Draft Determination, the AER determined that CitiPower's depreciation for each regulatory year should be as follows:[848]

	$m (nominal)					
	2011	2012	2013	2014	2015	Total
Depreciation	35.2	38.4	41.9	45.6	49.6	210.6

Table 1.3 Draft Determination - Depreciation

This depreciation calculation was based on the following asset lives:[849]

	2011-15 standard asset lives for new capex	2011-15 remaining asset lives
Subtransmission	50.0	22.1
Distribution system assets	49.0	21.6
Metering	N/A	6.1
Public lighting	N/A	13.3

[846] CitiPower, Post Tax Revenue Model (Attachment 2 to this Revised Regulatory Proposal).
[847] Initial Regulatory Proposal, p290.
[848] AER, Draft Determination, p477.
[849] AER, Draft Determination, p468.

	2011-15 standard asset lives for new capex	2011-15 remaining asset lives
SCADA/Network control	13.0	7.7
Non-network - IT	6.0	5.2
Non-network - Other	10.0	6.6
Equity raising costs	46.6	-

Table 11.4 Draft Determination - Asset lives (years)

11.5 CitiPower's response to the AER's Draft Determination

CitiPower accepts the AER's calculation of depreciation and asset lives set out in the Draft Determination, except that CitiPower considers that minor amendments and corrections are required to the AER's calculations. CitiPower's proposed amendments are set out in the change log to CitiPower's Roll Forward Model.

11.6 CitiPower's Revised Regulatory Proposal

CitiPower amends its Initial Regulatory Proposal to propose the following depreciation amounts (straight line depreciation less indexation of the RAB):

	$m (nominal)					
	2011	2012	2013	2014	2015	Total
Depreciation	34.8	38.6	42.7	46.9	52.5	215.5

Table 11.5 Revised Regulatory Proposal - Depreciation

The calculation of these amounts is set out in CitiPower's revised Post Tax Revenue Model, Roll Forward Model and Remaining Asset Life Model.

12. COST OF CAPITAL

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to the Draft Determination regarding the WACC.

This Chapter does not address the following issues that are related to the cost of capital but which were included in other chapters of the Draft Determination:

- Equity raising costs. That issue is addressed as part of capex in Chapter 9.
- Debt raising costs. That issue is addressed as part of opex in Chapter 6.
- The value of gamma (the assumed utilisation of imputation credits). That issue is addressed as part of the estimated cost of corporate income tax in Chapter 13.

12.1 Summary of key points

12.1.1 Debt Risk Premium

CitiPower does not accept the approach in the Draft Determination in relation to the method for calculating the DRP.

The Draft Determination adopted a DRP of 3.25 per cent, calculated based on the CBASpectrum service. CitiPower considers that the AER's method for assessing whether to use CBASpectrum or Bloomberg (or an average of them) to determine the DRP is unreliable and does not result in the selection of the service that produces the most accurate estimate of the DRP.

CitiPower proposes an alternative method developed by PwC for testing whether CBASpectrum or Bloomberg produces the more accurate estimate of the DRP. CitiPower considers that the decision whether to base the DRP on CBASpectrum or Bloomberg (or an average of them) should be made in accordance with this method rather than the AER's method.

CitiPower also considers that the AER's approach to extrapolating the Bloomberg curve to 10 years does not result in an accurate measure of the DRP. CitiPower proposes an alternative method for extrapolating the Bloomberg curve developed by PwC.

Based on CitiPower's proposed method, Bloomberg provides a more reliable estimate of the DRP over the averaging period used for this Revised Regulatory Proposal. Based on Bloomberg, CitiPower considers that the appropriate DRP is 4.28 per cent for the averaging period used for this Revised Regulatory Proposal.

CitiPower attaches an expert report from CEG critiquing the AER's approach for determining the DRP and proposing amendments that will enhance the robustness of the AER's approach. If the AER does not accept CitiPower's proposed approach for determining the DRP, then CitiPower proposes that the DRP should be determined in accordance with CEG's modifications to the AER's approach.

12.1.2 Market risk premium

Although CitiPower does not agree with the analysis underlying the AER's decision regarding the MRP in the Draft Determination, CitiPower adopts the MRP of 6.5 per cent set out in the Draft Determination.

12.1.3 Summary and other parameters

The following table sets out the values for the WACC parameters that were proposed by CitiPower in its Initial Regulatory Proposal, the values that were adopted by the AER in the Draft Determination, and the values that are proposed by CitiPower in this Revised Regulatory Proposal.

Parameter	Initial Regulatory Proposal	Draft Determination	Revised Regulatory Proposal	Does CitiPower adopt the approach in the Draft Determination?
Nominal risk free rate (Rf)	5.47%	5.65%	5.65%	Yes
Inflation rate (f)	2.44%	2.57%	2.57%	Yes
Equity beta (ße)	0.8	0.8	0.8	Yes
Market risk premium (MRP)	8.0%	6.5%	6.5%	Yes
Value of debt as a proportion of the value of equity and debt (D/V)	60%	60%	60%	Yes
Debt risk premium (DRP)	4.71% (Based on Bloomberg)	3.25% (Based on CBASpectrum)	4.28% (Based on Bloomberg)	**No**
Nominal WACC	**10.86%**	**9.68%**	**10.29%**	**–**

Table 12.1 WACC parameter values

The values for the nominal risk free rate, DRP and expected inflation rate are indicative only. The values for nominal risk free rate and DRP were calculated over the 30 business days from 19 April to 31 May 2010, which is the averaging period selected for the purpose of this Revised Regulatory Proposal.

Prior to the Final Determination, the nominal risk free rate and DRP will be replaced with data from the agreed averaging period and the expected inflation rate will be updated with the most recent RBA inflation forecasts. The changes in the values for the nominal risk free rate and expected inflation rate are due to the different period during which these indicative values were determined.

12.2 Debt risk premium

12.2.1 Rules requirements

Clause 6.5.2(e) of the Rules provides that the DRP is 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 rating agency.

The AER's SoRI did not determine a DRP. However, the SoRI did determine that:

- the credit rating for determining the DRP is BBB+;850 and
- the maturity for determining the nominal risk free rate, which is also the maturity that must be used for determining the DRP, is 10 years.[851]

12.2.2 CitiPower's Initial Regulatory Proposal

CitiPower proposed a DRP of 4.71 per cent in its Initial Regulatory Proposal. This value was based on the Bloomberg BBB 7 year fair value curve measured over the first 15 business days in October 2009, extrapolated to 10 years based on a linear extrapolation.[852]

CitiPower's method for determining the DRP was based on a report from PwC, which was attached to the Initial Regulatory Proposal.[853] The PwC report:

- set out a methodology to test whether the Bloomberg fair value curve reasonably meets the legislative requirements for determining the DRP;
- set out an alternative methodology for calculating the DRP that best meets the legislative requirements should Bloomberg fail the above test;
- applied these tests over the first 15 business days in October 2009;
- concluded that the Bloomberg fair value curve reasonably meets the legislative requirements over the first 15 business days in October 2009; and
- concluded that the appropriate measure of the DRP over the first 15 business days in October 2009 was 4.71 per cent.

In the Initial Regulatory Proposal, CitiPower observed that this proposed DRP of 4.71 per cent was an indicative value that would be updated in the Final Determination using data from the agreed averaging period.

CitiPower's Initial Regulatory Proposal proposed that the final DRP be determined by applying the methods set out in the PwC report during the agreed averaging period.[854]

The Initial Regulatory Proposal did not propose a departure from the SoRI in relation to the BBB+ credit rating or the 10 year maturity period.

12.2.3 AER's Draft Determination

In the Draft Determination, the AER adopted a value of 3.25 per cent for the DRP.[855] This value was determined based on the CBASpectrum fair value curves. It was measured over an indicative period of the 15 days ending on 19 March 2010.

[850] AER, SoRI (Attachment 174 to this Revised Regulatory Proposal).
[851] AER, SoRI (Attachment 174 to this Revised Regulatory Proposal), p7.
[852] Initial Regulatory Proposal, p299.
[853] PwC, Victorian Distribution Businesses Methodology to Estimate the Debt Risk Premium, November 2009 (Attachment P0079 to Initial Regulatory Proposal).
[854] Initial Regulatory Proposal, p299.
[855] AER, Draft Determination, p523.

In summary, the AER concluded that:

- it is appropriate to consider both Bloomberg and CBASpectrum in the calculation of the DRP;
- its approach to testing both CBASpectrum and Bloomberg data is appropriate and has been affirmed by the Tribunal;
- PwC's linear extrapolation methodology is inappropriate, and a proxy extrapolation using AAA fair yields would better estimate the 10 year BBB+ cost of debt;
- the use of CBASpectrum's BBB+ fair value curve provides the best available prediction of observed yields for the purposes of determining the yield on the benchmark BBB+ 10 year corporate bond because it meets the need for the return on debt to reflect the current cost of borrowings for comparable debt.[856]

As in the Initial Regulatory Proposal, the AER's proposed DRP is an indicative value that will be updated in the Final Determination using data from the agreed averaging period.

12.2.4 CitiPower's response to the AER's Draft Determination

CitiPower does not accept the AER's method for determining whether Bloomberg or CBASpectrum should be used to determine the DRP. CitiPower considers that the AER's method is unreliable for the reasons set out in sections 12.2.4.1 and 12.2.4.3 below, and that it is unreasonable to use that method.

CitiPower also does not accept the AER's method for extrapolating the Bloomberg fair value curve to produce a measure of the 10 year corporate bond rate, for the reasons set out in section 12.2.4.2 below.

CitiPower attaches an expert report by PwC on the method for assessing which of Bloomberg or CBASpectrum (or the average) provides the most reliable estimate of the DRP, including the method for extrapolating the Bloomberg fair value curve).[857] CitiPower considers that the most reliable method for determining the DRP is that developed by PwC and discussed in sections 12.2.4.1 and 12.2.4.2 below.

If for any reason the AER rejects CitiPower's proposed approach and continues to apply the framework set out in its Draft Determination, then CitiPower considers that the AER must make the amendments to its approach that are set out in the report from CEG discussed in section 12.2.4.3 below in order for the AER's approach to be a reasonable method for determining the DRP.

12.2.4.1 CitiPower's proposed method for testing Bloomberg and CBASpectrum

CitiPower accepts the AER's view that the DRP should be determined using the Bloomberg fair value curve or the CBASpectrum fair value curve (or the average of them).

[856] AER, Draft Determination, pp522-523.
[857] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).

CitiPower considers that the decision whether to use Bloomberg or CBASpectrum (or the average) should be based on the tests set out in PwC's report. PwC proposes an approach that involves the following four steps:[858]

- test the integrity of the fair value curves to the extent possible;
- test the predictive accuracy of the fair value curves, by applying the average error test and the weighted sum of squared errors test;
- test the extrapolation of the curve beyond the data points, which were limited to 5-6 years in the sample of BBB+ bonds currently on issue; and
- draw on other information as a cross-check, which may include the yields on floating rate note yields (adjusted to a fixed rate equivalent yield), evidence from other bond ratings and other estimates of fair value yield curves.

PwC applied these tests to Bloomberg and CBASpectrum and concluded that:[859]

> *'We find that the Bloomberg BBB band fair value curve provides a more accurate prediction of the estimates from different providers of the yields of Australian BBB+ corporate bonds than the alternatives that the AER offers (namely the CBASpectrum BBB+ fair value curve and average of the Bloomberg BBB band and CBASpectrum curves).'*

PwC reviewed the AER's approach in the Draft Determination and concluded that the AER's approach involved the following significant errors:[860]

- Exclusion of the DBCT bond as an outlier. The DBCT bond should be included in the sample of BBB+ bonds due to:
    - its importance as the longest dated bond in this rating category, which should raise the standard of proof to reject it;
    - recent pronouncements by Standard & Poor's confirm its BBB+ rating; and
    - the AER's reasons for rejecting the DBCT bond as an outlier are not persuasive.
- Focussing only on squared errors, not testing whether the predicted yield is downward biased. The AER's focus on minimising squared errors does not provide information on whether the relevant fair value curve may systematically under- or over-estimate the underlying yield data.
- Not testing how the debt risk premium should increase beyond 5 or 6 years. The AER has only tested the respective fair value curves up to a term of 5-6 years. The AER has not tested whether the increase in the debt risk premium between 5 and 10 years predicted by CBASpectrum is reasonable against other evidence. PwC finds that during the reference period, the CBASpectrum BBB+ debt risk premium increased by only 21 basis points between 5 and 10 years, compared to the Bloomberg AAA-band debt risk premium which increased by 83 basis points. PwC also observes that two

[858] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), pp3-4.

[859] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), p2.

[860] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), pp5-7.

Telstra A rated bonds with 5 and 10 year terms currently exhibit a change in the debt risk premium of 56 to 84 basis points (depending on data source). Against these benchmarks, PwC considers that CBASpectrum's prediction of a 21 basis point increase in the debt risk premium between 5 and 10 years is implausibly low.

- Failure to consider a wider range of sources of information. By restricting its attention only to the Bloomberg and CBASpectrum fair value curves and the limited number of BBB+ rated Australian corporate bonds on issue, the AER has ignored other potentially useful sources of information that may assist in improving the estimate of the debt risk premium that is commensurate with prevailing conditions in the market for a 10 year BBB+ Australian corporate bond.

During the averaging period used for this Revised Regulatory Proposal, CitiPower does not consider that any bonds should be treated as outliers and excluded from the analysis.

Applying PwC's tests to the relevant measurement period of the 30 business days from 19 April to 31 May 2010, the Bloomberg fair value curve provides the most reliable estimate of the DRP.

12.2.4.2 CitiPower's proposed method for extrapolation of Bloomberg

Bloomberg's longest maturity BBB fair value curve is currently 7 years. It is accepted by the AER that this curve must be extrapolated to 10 years when assessing the DRP.[861]

CitiPower considers that extrapolation of the Bloomberg curve should be performed by using the methodology set out in the attached report from PwC,[862] which involves using the Bloomberg BBB fair value curve to 6 years and then extrapolating it using the Bloomberg AAA curve to 10 years.

As explained in the report by PwC:[863]

- Extrapolating from the Bloomberg BBB curve at the 6 year mark is most appropriate because the longest dated bond in the sample during the relevant measurement period has a term of approximately 5-6 years.
- The BBB curve should then be extrapolated to 10 years using the Bloomberg AAA curve because the Bloomberg AAA curve is less reliant on the slope of the Bloomberg curve at any interval. As the Bloomberg curve is often a series of discontinuous line-segments, this approach reduces the risk of an aberrant value from the linear extrapolation. However, this is a conservative approach and is likely to understate the correct DRP, as the AAA curve would be expected to understate the slope of the BBB curve.
- PwC notes that Bloomberg ceased publishing a AAA 10 year curve from 22 June, although it is possible that it may restart publishing that curve in the future. If the AAA 10 year curve is published at the time of the agreed averaging period, then that curve should be used as discussed above. If the AAA 10 year curve is not published at

[861] AER, Draft Determination, p521.
[862] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).
[863] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), pp22-23.

the time of the agreed averaging period, then the AER should use the average of the 10 year AAA curve over the latest period for which it was available.

12.2.4.3 CEG's critique of the AER's approach and enhancements to that approach

The Victorian DNSPs commissioned a report from CEG entitled 'Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates, A report for Victorian Electricity DBs'.[864] The CEG report:

- critiques the AER's approach in the Draft Determination for determining the DRP; and
- proposes amendments to the AER's approach that will enhance the robustness of the AER's approach.

The CEG report identifies the following problems with the AER's approach in the Draft Determination:

- the AER's approach asks the wrong question and is not a reasonable test for assessing which of CBASpectrum or Bloomberg provides the best estimate of the 10 year BBB+ corporate bond rate. The CEG report states:[865]

  > *'The methodology adopted by the AER in the Draft Decision attempts to test which of the Bloomberg or the CBASpectrum BBB+ fair value curves better fits the available estimates of bond yields. The AER uses a small sample of only five bonds with an average maturity of just 3.6 years to maturity to perform this test (with individual bonds maturities ranging from 2.2 to 5.4 years). Once the AER has determined which of the fair value curves it considers to be a better fit to the available data the AER then uses the 10 year fair value estimate from that curve to determine the NER cost of debt.*
  >
  > *In our view, this involves an important error in that the AER methodology is not attempting to answer the correct question (the 'wrong question error'). Specifically, the correct question is which of the fair value curves best estimates the 10 year BBB+ cost of debt. However, by applying the AER's test to the AER's sample of bond yields it has effectively asked which curve best estimates the cost of debt for maturity of around 3.6 years.'*

- the AER's approach does not consider all relevant information and excludes the vast majority of potentially relevant corporate bonds from its sample;
- the AER should also consider information regarding:
  - fixed coupon BBB+ bonds that are covered by one or two of UBS, CBASpectrum or Bloomberg, rather than only considering bonds that are covered by all three;
  - BBB+ floating rate bonds;
  - bonds that do not have a BBB+ rating, such as BBB or A- rated bonds; and

[864] CEG, Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates, A report for Victorian Electricity DBs', July 2010 (Attachment 176 to this Revised Regulatory Proposal).
[865] CEG, Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates, A report for Victorian Electricity DBs', July 2010 (Attachment 176 to this Revised Regulatory Proposal), p1.

  - bonds that are issued in Australia by foreign companies;
- the AER's failure to consider this information is particularly problematic given the short maturity of the bonds in the AER's sample and the absence of any 10 year BBB+ fixed coupon corporate bonds;
- the AER's failure to consider this information is what CEG terms 'a non corresponding data set error' and means that the AER fails to have regard to the most relevant information required to answer the correct question of which of CBASpectrum or Bloomberg provides the most reliable estimate of the 10 year BBB+ corporate bond rate; and
- the AER's tests for outliers are inappropriate, in particular because:
  - the AER applies its tests over an incorrect timeframe, using the period from 2 January 2009 until the end of the DRP measurement period, when the relevant question is whether the bond is an outlier during the DRP measurement period and therefore the test should only be applied during the DRP measurement period;
  - the AER only considers the yield on a potential outlier bond against the other 5 bonds in the AER's sample, but to be a reliable test the AER must consider other data;
  - the AER does not adjust for maturity when considering if a bond is an outlier, which is an error given it is well understood that yields increase with maturity and the fact that a longer maturity bond has a higher yield should not result in it being treated as an outlier;
  - the Chow test is not a useful test for these purposes; and
  - applied correctly, the outlier tests would show that the DBCT bond is not an outlier.

CEG considers that the following amendments to the AER's approach are required to improve the robustness of that approach:

- the AER's tests should also consider information regarding:
  - fixed coupon BBB+ bonds that are covered by one or two of UBS, CBASpectrum or Bloomberg, rather than only considering bonds that are covered by all three;
  - BBB+ floating rate bonds;
  - bonds that do not have a BBB+ rating, such as BBB or A- rated bonds; and
  - bonds that are issued in Australia by foreign companies; and
- the AER's test for outliers should:
  - be applied over the DRP measurement period;
  - account for differences in maturity;
  - use the classic test, the box plot test and Chauvenet's test; and
  - consider all relevant bonds, including the four additional types of information noted above.

The CEG report demonstrates why it is incorrect and unreasonable for the AER to apply the approach set out in the Draft Determination to determine the DRP.

Also attached to this Revised Regulatory Proposal is a companion report from CEG entitled 'Detailed application of AER cost of debt methodology to alternative bond samples, A report for Victorian DBs'.[866] That report explains the results of applying CEG's proposed adjustments to the AER's methodology during the measurement period used for this Revised Regulatory Proposal.

CitiPower considers that the appropriate method to determine the DRP is that set out in sections 12.2.4.1 and 12.2.4.2 above. However, if the AER rejects CitiPower's proposed approach and continues to apply the framework set out in its Draft Determination, CitiPower considers that the AER must make the amendments to its approach that are set out in the CEG reports in order for the AER's approach to be a reasonable method for determining the DRP.

12.2.4.4 Additional matters

In the Draft Determination, the AER stated that: [867]

> *'In its recent review of the AER's New South Wales distribution determination, the Australian Competition Tribunal also affirmed the AER's method of comparing the fair yield curves of data service firms against the actual bond yields to assess the reliability of data service providers.'*

That statement is not an accurate description of the Tribunal's decision.

The Tribunal only determined that, in the particular circumstances of the NSW distribution determinations, it would have been an error for the AER to adopt an average of Bloomberg and CBASpectrum. The Tribunal did not affirm the AER's approach for testing whether Bloomberg or CBASpectrum was more reliable. In particular, the following statement by the Tribunal shows that it was not endorsing the use of the AER's approach for future determinations: [868]

> *'No doubt in future revenue determinations the AER will need to consider again the data sources and methodology. That will certainly be the case if there are competing series and continuing divergence between them.'*

12.2.5 CitiPower's Revised Regulatory Proposal

CitiPower revises its Initial Regulatory Proposal in relation to the method for determining the DRP as follows:

- The DRP should be determined based on the CBASpectrum or Bloomberg fair value curves, or an average of CBASpectrum and Bloomberg.

[866] CEG, Detailed application of AER cost of debt methodology to alternative bond sample, A report for Victorian DBs, July 2010 (Attachment 266 to this Revised Regulatory Proposal).
[867] AER, Draft Determination, p520.
[868] *Application by Energy Australia and Others* [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at 122.

- The decision whether to base the DRP on the CBASpectrum or Bloomberg fair value curves (or an average of them) should be made in accordance with CitiPower's proposed method set out in section 12.2.4.1 above and the attached expert report from PwC. 869
- Extrapolation of the Bloomberg curve should be performed by using the Bloomberg BBB fair value curve to 6 years and then extrapolating it using the Bloomberg AAA curve to 10 years, in accordance with the report from PwC. If the Bloomberg AAA curve is not published during the agreed averaging period, then the AER should use the average of the Bloomberg AAA curve over the latest period for which it was available.
- If the CBASpectrum curve (or the average) is considered to be the appropriate curve to use, then only the 5 year measurement from the CBASpectrum curve should be used and to that 5 year observation should be added an amount equal to the change in the Bloomberg AAA fair value curve between a 5 and 10 year term.
- Based on CitiPower's proposed method, the Bloomberg fair value curve provided the more reliable estimate of the DRP based on a measurement period of the 30 business days from 19 April to 31 May 2010. That assessment will need to be repeated for the agreed averaging period.
- Based on CitiPower's proposed method and a measurement period of the 30 business days from 19 April to 31 May 2010, CitiPower considers that the appropriate indicative DRP is 4.28 per cent. Prior to the Final Determination, this indicative value will be replaced with data from the agreed averaging period.
- If the AER does not accept CitiPower's proposed approach for determining the DRP, then the decision whether to base the DRP on the CBASpectrum or Bloomberg fair value curves (or an average of them) should be made in accordance with the modifications to the AER's approach that are set out in the report from CEG.[870]

12.3 Market risk premium

12.3.1 Rules requirements

Clause 6.5.2(b) of the Rules sets out the formula for calculating WACC. One of the parameters in that formula is the MRP. The Rules do not define the MRP or specify how it is to be calculated.

In the SoRI, the AER adopted a value of 6.5 per cent for the MRP.[871]

Clause 6.5.4 of the Rules provides that a distribution determination must be consistent with the SoRI unless there is persuasive evidence justifying a departure from the value set out in the SoRI. In deciding whether a departure from the SoRI is justified, the AER must consider:

- the underlying criteria on which the value was set in the SoRI; and

[869] PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).
[870] CEG, Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates, A report for Victorian Electricity DBs', July 2010 (Attachment 176 to this Revised Regulatory Proposal).
[871] AER, SoRI (Attachment 174 to this Revised Regulatory Proposal), p7.

- whether, in light of the underlying criteria, a material change in circumstances since the date of the SoRI, or any other relevant factor, now makes the value set out in the SoRI inappropriate.

12.3.2 CitiPower's Initial Regulatory Proposal

CitiPower proposed an MRP of 8.0 per cent in its Initial Regulatory Proposal.[872] The Initial Regulatory Proposal stated that there is persuasive evidence to demonstrate that the MRP of 6.5 per cent set out in the SoRI is inappropriate and that a departure from that value is justified.

The Initial Regulatory Proposal stated that a departure from the SoRI is justified on the basis of:

- the on-going uncertainty regarding the outlook for global economic and capital market conditions;
- new evidence regarding investors' forward-looking required rates of return in the present environment of on-going high uncertainty, as supported by an expert report from Bishop and Officer873; and
- CitiPower's contention that under the prevailing conditions in the market, applying the MRP value specified in the SoRI would deliver an outcome that is inconsistent with the NEO and the revenue and pricing principles set out in the NEL.[874]

12.3.3 AER's Draft Determination

In the Draft Determination, the AER adopted an MRP of 6.5 per cent.[875] The AER considered that there was not persuasive evidence to demonstrate that a departure from the MRP set out in the SoRI is justified.

In summary, the basis for the Draft Determination was that:

- commentary on financial markets indicates clear signs of stabilisation since the time of the SoRI and the AER's decision to increase the MRP to 6.5 per cent;
- Officer and Bishop's implied volatility and glide path analysis is subject to limitations as addressed by the AER in previous regulatory determinations;
- no persuasive evidence exists to support a long term historical average of 7 per cent for the MRP as assumed by Officer and Bishop;
- Officer and Bishop have not adequately demonstrated that the current level of credit spreads are explained by movements in the MRP; and
- the AER considered that a MRP of 6.5 per cent may be considered conservative when accounting for current prevailing conditions.876

[872] Initial Regulatory Proposal, p304.
[873] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium Estimate for 2011 to 2015, October 2009 (Attachment C0194 to the Initial Regulatory Proposal).
[874] Initial Regulatory Proposal, pp300-304.
[875] AER, Draft Determination, p503.
[876] AER, Draft Determination, p503.

12.3.4 CitiPower's response to the AER's Draft Determination

CitiPower does not agree with the analysis underlying the AER's adoption of this value for the MRP and continues to consider that the true MRP is 8.0 per cent as set out in the Initial Regulatory Proposal.

CitiPower notes that market conditions have significantly deteriorated since:

- the date of the Draft Determination; and
- the date of the analysis relied on in the Draft Determination, which only covers the period up to January to March 2010.[877]

This change in market conditions indicates that the MRP will have risen since the date of the Draft Determination and remains significantly above normal levels.

12.3.4.1 Officer and Bishop report

The Victorian DNSPs commissioned a report from Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associated entitled 'Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers' [878] This further Officer and Bishop report represents the most up-to-date information regarding the level of the MRP.

The Officer and Bishop report states that: [879]

> *'an MRP of 6.5% does not reflect current economic conditions, and nor does it reflect what may prevail over the regulatory period. Current high levels of market risk demand a risk premium over the long term average and this, in our view, means 6.5% will not reward investors for average market risk anticipated over the next five year regulatory period.'*

The Officer and Bishop report undertakes an analysis of the levels of volatility in the market and concludes that current market volatility is well above the historical average. Officer and Bishop note that the higher than average volatility experienced during the peak of the GFC diminished to an extent but then recently rebounded, as shown by the following graph: [880]

[877] See for example the graphs on pp501-503 of the Draft Determination.
[878] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal).
[879] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal) p27.
[880] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal), Figure 1, p3.

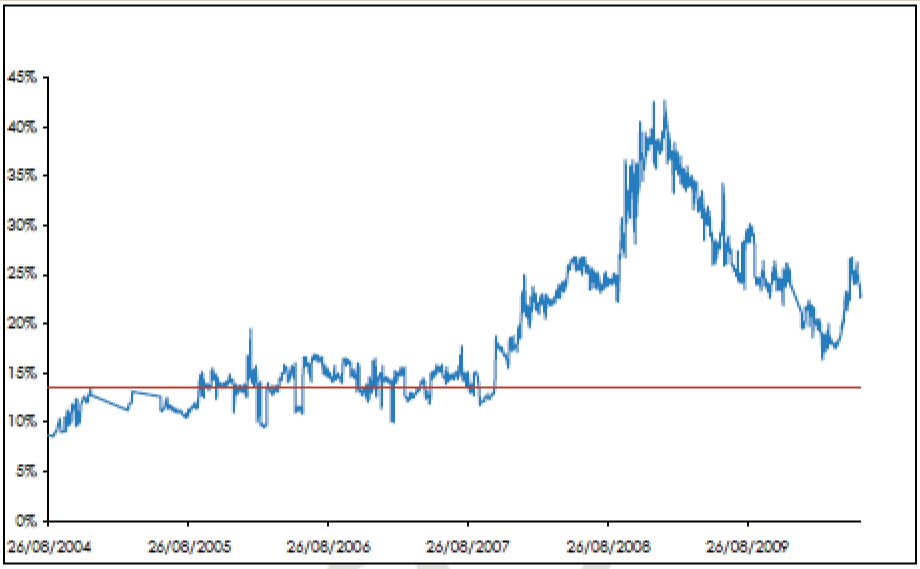


Figure 12.1 Implied volatility of 12 month options on the ASX 200

The Officer and Bishop report states that: [881]

> *'Using this view of volatility, combined with a long term average of the historical MRP, we estimate that a one year forward view of the MRP is 11.9% and the 'average' forward view over the period 2011 – 2015 to is 8%.'*

Officer and Bishop consider the appropriate method for determining the MRP for the regulatory control period, which requires an assessment to be made as to the current MRP, the appropriate glide path to the long term average MRP, the likely rate of decline, and the appropriate time period over which to determine the MRP.

Officer and Bishop analyse various sources of data and note that if history is a guide then the 2007 crash will take 6 ½ years to recover from, ie from December 2007 until June 2014.[882] Officer and Bishop consider that a reasonable estimate of the period during which the MRP will be above historical levels as a result of the GFC is 4-5 years.[883]

Officer and Bishop consider that the range of the MRP over the 2011-15 regulatory control period is likely to be between 8.2 per cent and 11.9 per cent, depending on whether the MRP declines to the historical level after 1, 3 or 5 years. In concluding that the appropriate MRP for the 2011-15 period is 8.0 per cent, Officer and Bishop note that they are taking a conservative view and adopting an estimate at the lower end of the range.[884]

[881] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal), p3.
[882] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal), p12.
[883] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal), p14.
[884] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal), p19.

- The Officer and Bishop report concludes that: [885]

  'We reinforce our view that a MRP of 8% for the 2011 to 2015 regulatory period reflects current circumstances and a view as to what will prevail over the regulatory period.'

The Officer and Bishop report also responds to several criticisms that the AER made of previous reports by Officer and Bishop in the Draft Determination and the South Australian Final Determination.

12.3.4.2 Other comments

CitiPower considers that the AER's approach in the Draft Determination of estimating the MRP over a 10 year period is incorrect. The AER states that it uses a 10 year estimation period because it is consistent with the term set for the risk-free rate in the SoRI.[886] However, the purpose of the WACC is to determine the cost of capital that would be required over the regulatory control period by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the DNSP. The Rules therefore require the AER to determine a WACC that is appropriate over the term of the regulatory control period.

The need for the WACC parameters to be estimated over the term of the regulatory period was recently confirmed by the Tribunal's decision in *Application by Telstra Corporation Limited*.[887] In that decision, the Tribunal stated: [888]

> *'An undertaking has effect over a period, and the price it sets need to be appropriate for the period.*
>
> ...
>
> *The Tribunal notes that the use of the WACC formula is only a means to an end, which is to estimate the required rate of return for an investment with certain characteristics of riskiness and debt. That rate of return is unlikely to vary greatly over the short to medium term, and should not therefore be overly subject to the vagaries of short-term movements in parameters such as market interest rates. Moreover, the rate of return applies over the period of the undertaking. Both the access provider and the ACCC should keep these facts in mind to ensure that they do not, by lighting on parameter values that are unrepresentative, end up with a rate of return that is inappropriate to its purpose.*'

The AER must therefore determine an accurate estimate of the MRP that is likely to apply over the next 5 years. In the current market conditions, that approach is likely to result in a higher MRP than if a 10 year timeframe was used.

[885] Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010 (Attachment 177 to the Revised Regulatory Proposal), p2.
[886] AER, Draft Determination, p490.
[887] [2010] ACompT 1 (Attachment 179 to this Revised Regulatory Proposal).
[888] [2010] ACompT 1 (Attachment 179 to this Revised Regulatory Proposal) at [419] and [422].

CitiPower also notes that the IMF recently issued a Working Paper entitled 'Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis', which considered current market conditions in Australia and concluded that: [889]

> *'A higher cost of capital may become a long-lasting legacy of the recent global crisis, weighing on future investment.'*

This comment demonstrates that the MRP has not fallen to its pre-GFC level, and may not do so even in the long-term.

However, for the purposes of the Final Determination only, CitiPower adopts the MRP of 6.5 per cent as set out in the Draft Determination and does not propose a departure from the SoRI.

12.3.5 CitiPower's Revised Regulatory Proposal

Despite continuing to consider that the most appropriate MRP is 8.0 per cent, CitiPower amends its Initial Regulatory Proposal to adopt a value of 6.5 per cent for the MRP as set out in the Draft Determination.

12.4 Other WACC parameters

Subject to a minor issue regarding the expected inflation rate, the Draft Determination accepted the values for the following WACC parameters, or the methods for calculating those values, that were proposed in CitiPower's Initial Regulatory Proposal:

- nominal risk-free rate;890
- expected inflation rate;891
- gearing level (value of equity as a proportion of the value of equity and debt);892 and
- equity beta.893

CitiPower does not make any amendments to its Initial Regulatory Proposal in relation to these parameters.

CitiPower notes that the indicative values for the nominal risk free rate and expected inflation rate set out in the Initial Regulatory Proposal have been updated and are:

- nominal risk free rate: 5.65 per cent; and
- expected inflation rate: 2.57 per cent.

The nominal risk free rate is calculated over the 30 business days from 19 April to 31 May 2010, which is the averaging period selected for the purpose of this Revised Regulatory Proposal.

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[889] IMF, IMF Working Paper, Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis, May 2010 (Attachment 178 to the Revised Regulatory Proposal).
[890] AER, Draft Determination, p488. This indicative rate was measured over the 15 days ending on 19 March 2010.
[891] AER, Draft Determination, p525.
[892] AER, Draft Determination, p485.
[893] AER, Draft Determination, p505.

Prior to the Final Determination, this indicative nominal risk free will be replaced with data from the agreed averaging period and this indicative expected inflation rate will be updated with the most recent RBA inflation forecasts.

12.5 Regulatory Information Notice response

Paragraphs 2.3 and 2.4 of the Further RIN require CitiPower to:

- identify each proposed departure from a WACC parameter set out in the SoRI; and
- for each such departure, provide all supporting consultants reports and documents.

CitiPower does not propose any departures in respect of the WACC parameters discussed in this Chapter 12 from those set out in the SoRI.

13. ESTIMATED CORPORATE INCOME TAX

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 12 of the Draft Determination regarding the estimated cost of corporate income tax.

This Chapter includes the issue of the value of gamma (the assumed utilisation of imputation credits). Gamma was addressed in the rate of return on capital Chapter of CitiPower's Initial Regulatory Proposal, but was addressed in the estimated corporate income tax Chapter of the Draft Determination.

13.1 Summary of key points

CitiPower does not accept the AER's decision in the Draft Determination to adopt a value of 0.65 for gamma.

CitiPower maintains that, in light of the underlying criteria, a material change in circumstances since the date of the SoRI or another relevant factor makes the value for gamma set out in the SoRI inappropriate. CitiPower considers that the appropriate value for gamma is 0.5.

CitiPower adopts the AER's approach in the Draft Determination in relation to changes in tax laws and tax depreciation of equity raising costs, except that the company tax rate reduction should be amended to reflect the Government's announcements that the proposed reduction to 28 per cent will not occur.

13.2 Gamma (assumed utilisation of imputation credits)

13.2.1 Rules requirements

The Rules require an assumption regarding the utilisation of imputation credits to calculate the cost of corporate income tax of a DNSP for each regulatory year. Clause 6.5.3 of the Rules requires that the cost of corporate income tax be calculated in accordance with the following formula:

$$ETC = (ETI \text{ x } r)(1 - \gamma)$$

where:

ETI is the estimated taxable income for the regulatory year;

r is the statutory income tax rate; and

γ (gamma) is the assumed utilisation of imputation credits.

Gamma is conventionally estimated using the Monkhouse formulation, under which gamma is the product of:[894]

- the payout ratio, which is the share of created imputation credits that are distributed to shareholders; and
- theta, which represents the market value of imputation credits as a proportion of their face value.

[894] Monkhouse P (1993), 'The cost of equity under the Australian dividend imputation tax system', *Accounting and Finance*, volume 33,(Attachment 181 to this Revised Regulatory Proposal), pp1-18.

The Rules also require the AER to carry out a review of rate of return parameters every five years and issue a SoRI adopting values, methods and credit rating levels for DNSPs or specified classes of DNSPs.[895] A distribution determination to which a SoRI is applicable must be consistent with the SoRI unless there is *'persuasive evidence justifying a departure, in a particular case, from a value, method or credit rating level set in the statement'*.[896] In determining whether a departure from a SoRI is justified in a distribution determination, the AER is required to consider:[897]

- the criteria on which the value, method or credit rating level was set in the SoRI; and
- whether a material change in circumstances since the date of the SoRI, or any other relevant factor, now makes the value, method or credit rating level set in the SoRI inappropriate.

As required by the Rules, the AER concluded its first review of rate of return parameters on 1 May 2009 and issued its SoRI. The SoRI set a value for gamma of 0.65.[898] In the SoRI Final Decision, the AER justified this on the grounds that:[899]

- an assumed payout ratio of 100 per cent appeared reasonable and consistent with the Officer framework;
- the value of theta should be 0.65, being the midpoint of the values produced by dividend drop-off studies and taxation studies . The only dividend drop-off study relied upon by the AER was Beggs and Skeels, 'Market arbitrage of cash dividends' (2006) 82 (258) *The Economic Record* 239 (**Beggs and Skeels (2006)**), which produced an estimate for theta of 0.57. The AER did not place any weight on the more up-to-date findings of the dividend drop-off study by SFG, 'The impact of franking credits on the cost of capital of Australian firms', 18 September 2008 (**SFG (2009)**), which produced substantially lower estimates of theta. The AER relies on tax studies to provide an 'upper bound' for theta. It derives an upper bound of 0.74, being the mid-point of the range of values from the tax studies (the range being 0.67 to 0.81).

In the Draft Determination, the AER stated that the underlying criteria on which the value of gamma was set in the SoRI are:

- the need for the rate of return to be a forward looking rate of return that is commensurate with the prevailing conditions in the market for funds and the risk involved in providing regulated distribution services;
- the need to achieve an outcome that is consistent with the NEO;
- the need for persuasive evidence before adopting a value or method that differs from the value or method previously adopted;
- the relevant revenue and pricing principles, which are: [900]

[895] Rules, clause 6.5.4.
[896] Rules, clause 6.5.4(g).
[897] Rules, clause 6.5.4(h).
[898] AER, SoRI (Attachment 174 to the Revised Regulatory Proposal).
[899] AER, SoRI Final Decision, p466. (Attachment 175 to the Revised Regulatory Proposal).
[900] AER, Draft Determination, pp529-530.

- providing a service provider with a reasonable opportunity to recover at least the efficient costs;
- providing a service provider with effective incentives in order to promote efficient investment; and
- having regard to the economic costs and risks of the potential for under and over investment.

The gamma of 0.65 adopted in the SoRI was a departure from the previous prevailing value for gamma. Prior to the SoRI, the value for gamma for all electricity distribution and transmission businesses in Australia had been 0.5.[901]

0.5 is also the value for gamma generally adopted by regulators in relation to other industries in Australia. For example, the ACCC adopted a gamma of 0.5 in its ULLS Final Decision, which was released only three days before the SoRI Final Decision.[902]

13.2.2 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower proposed a departure from the value of gamma set in the SoRI, as did all of the other Victorian DNSPs. CitiPower and all of the other DNSPs except Jemena proposed a value of 0.5,[903] while Jemena proposed a value of 0.2.[904]

All of the DNSPs' proposals argued that there was persuasive evidence justifying a departure from the SoRI value for gamma. This included the fact that there appeared to be a number of weaknesses in the AER's reasoning in the WACC review and the criteria on which the SoRI value was set. Furthermore, there was evidence before the AER of a material change in circumstances since the date of the SoRI which means that the value of 0.65 is now inappropriate.

Specifically in relation to the payout ratio, the DNSPs cited similar concerns to those raised by ETSA in the South Australian distribution price review process. The DNSPs referred to the expert evidence of Professor Robert Officer[905] (architect of the CAPM Officer Framework) and tax lawyer Peter Feros[906] who both reject the assumption that all imputation credits are distributed to shareholders. The DNSPs also noted the findings of the Officer and Hathaway (2004) study which estimated a payout ratio of 0.71.[907] Jemena further noted the conclusions of a tax study prepared for Jemena by Synergies,[908] which found that between 2003-07 the payout ratio averaged 66 per cent, based on tax statistics.[909]

[901] AER, SoRI Final Decision (Attachment 175 to this Revised Regulatory Proposal), p395.
[902] ULLS Final Decision, Chapter B.7 of Appendix (B) (Cost of Capital) (Attachment 180 to this Revised Regulatory Proposal). The AER's Proposed SoRI, which first proposed a gamma of 0.65, was released on 11 December 2008 and the AER's final SoRI was released on 1 May 2009.
[903] Initial Regulatory Proposal, p307.
[904] Jemena, Regulatory Proposal 2011-2015, 30 November 2009, p175.
[905] Robert R. Officer, Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers, 23 June 2009 (Attachment 185 to this Revised Regulatory Proposal).
[906] Peter Feros, Review of WACC parameters: Gamma, ETSA Price Reset, 22 June 2009 (Attachment 182 to the Revised Regulatory Proposal).
[907] N. Hathaway and B. Officer, The Value of Imputation Tax Credits – Update 2004, Capital Research Pty Ltd, November 2004 (Attachment 183 to the Revised Regulatory Proposal) pp13 and 24 (**Officer and Hathaway (2004)**).
[908] Synergies Economic Consulting, Gamma: New Analysis Using Tax Statistics, 28 May 2009.
[909] Jemena, Regulatory Proposal 2011-15, 30 November 2009, p178.

The DNSPs argued that the value of theta should be less than that set in the SoRI, and submitted evidence to support this claim. The key evidence relating to the value of theta was a report by Professor Skeels reviewing the SFG (2009) study which produced a substantially lower value of theta. Professor Skeels noted that the AER arguments against the use of the SFG study were 'unconvincing' and were in fact nothing more than allusions to potential problems which required further investigation. Professor Skeels conducted such an investigation of the SFG study and found its results to be convincing. His report concluded: [910]

> *'This leads me to consider that their [SFG's] estimate of theta of 0.23 is the best such estimate currently available for Australia. It might be argued that their methodology does not perfectly replicate that of Beggs and Skeels (2006) and that the remaining differences may downwardly bias the estimates provided by SFG in Appendix I. I am not one who shares that view as I think their analysis is now compelling. However, if one was to take that view then I think that a very strong case could be made for the true value of theta to lie somewhere between the SFG estimate of 0.23 and the Beggs and Skeels (2006) estimate of 0.57, and in all probability to lie towards the lower end of that range. Any higher value for theta seems completely implausible, both in terms of the empirical evidence presented and in terms of the theoretical arguments underpinning them.'*

Jemena also noted the findings of the Synergies tax study[911] which estimates that investors on average only utilise 35 per cent of the credits that they receive.

13.2.3 AER's Draft Determination

In the Draft Determination, the AER rejected the DNSPs' proposals for a departure from the SoRI value of 0.65. The Draft Determination drew on two new reports commissioned by the AER:

- a report by Associate Professor John Handley of the University of Melbourne (Handley Report);912 and
- a report by Professor Michael McKenzie and Associate Professor Graham Partington on behalf of the Securities Industry Research Centre of Asia-Pacific (McKenzie and Partington Report).913

In relation to the payout ratio, the AER stated that the evidence presented by Jemena had already been considered as part of the WACC review. The AER repeated its contention that a payout ratio of 100 per cent is consistent with the Officer CAPM Framework, which assumes that cash flows occur in perpetuity and are therefore fully distributed at the end of each period. The AER also asserted that even where imputation credits are retained, they will still hold value. The AER noted and agreed with the advice of its experts (including McKenzie and Partington) that the actual payout ratio is likely to be between 70 per cent

910 Christopher L Skeels, A Review of the SFG Dividend Drop-Off Study – A Report prepared for Gilbert and Tobin, 28 August 2009, p31(Attachment 188 to the Revised Regulatory Proposal).
911 Synergies Economic Consulting, Gamma: New Analysis Using Tax Statistics, 28 May 2009.
912 Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010.
913 Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010.

and 100 per cent. Nonetheless, the AER adopted a value at the top of this range, noting that *'the assumption of a 100 per cent payout ratio simplifies the framework for estimating gamma'*.[914]

In relation to theta, the AER stated in its Draft Determination that it does not consider the report by Professor Skeels to represent persuasive evidence. The AER noted that although Professor Skeels appeared to address a number of the AER's concerns with the SFG study, there were still a significant number of issues which demonstrated that SFG's estimates were likely to be unreliable.

In its Draft Determination the AER relied heavily on the two new reports on gamma which it had commissioned. On the basis of these reports the AER expressed the following concerns:

- McKenzie and Partington's analysis demonstrates that SFG's regression results are likely to be affected by multicollinearity and as a result the values of imputation credits are likely to be downwardly biased;915
- the SFG (2009) study has problems with consistency in parameter estimation and data reliability remains an issue;
- based on McKenzie and Partington's advice, SFG's use of the Cook's D-statistic is likely to be less reliable than the filtering methodology used by Beggs and Skeels (2006);916
- the number of zero and negative drop-offs in SFG's data set is abnormally high; and
- the AER notes the conclusions of the Handley report that taxation studies may provide a reasonable estimate of the upper bound for theta.

The remainder of this Chapter addresses each of the arguments made by the AER in its Draft Determination and the accompanying expert reports.

13.2.4 CitiPower's response to the AER's Draft Determination

13.2.4.1 Payout ratio

There is now a considerable volume of persuasive evidence before the AER that would justify a departure from the assumption of a 100 per cent payout ratio. In addition to the evidence presented by the DNSPs in their regulatory proposals (particularly the expert evidence of Professor Officer and Mr Feros and the findings of the Officer and Hathaway (2004) study), there is also new evidence from the AER's own expert advisors which demonstrates that the payout ratio is less than 100 per cent.

McKenzie and Partington refer to the actual payout ratio as being 'about 70 per cent',[917] in line with the findings of Officer and Hathaway (2004) and more recently NERA (2010).[918]

[914]AER, Draft Determination, p537.
[915] AER, Draft Determination, pp542-545.
[916] AER, Draft Determination, p548.
[917] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p27.
[918] NERA, Payout ratio of regulated firms, report for Gilbert and Tobin, 5 January 2010 (Previously provided to the AER under cover of an email to C Pattas of the AER from B Cleeve of CitiPower and Powercor Australia on 22 February 2010) (**NERA (2010)**) (Attachment 184 to this Revised Regulatory Proposal).

McKenzie and Partington go on to conclude that the appropriate payout ratio for the purposes of estimating gamma should lie between 70 per cent and 100 per cent, since undistributed credits will have at least some value. It is noted that the AER implicitly assumes that either there is 100 per cent payout (an assumption which McKenzie and Partington consider to be unrealistic) or undistributed credits have the same value as distributed credits:[919]

> *'The AER makes the assumption that there is a 100 percent payout of imputation credits. Taken literally, this is clearly incorrect. However, we view the 100 percent payout assumption as simply a convenient step designed to allow for the value of undistributed franking credits when computing gamma. It is equivalent to saying that undistributed franking credits have the same value as distributed franking credits. In principle, this is likely to overstate the value of the undistributed credits, but it is not clear by how much.'*

McKenzie and Partington also consider the assumption that undistributed and distributed credits hold the same value to be unrealistic. They note that:[920]

> *'Clearly, undistributed credits will be discounted relative to distributed credits…'*

The Handley Report reaches a similar conclusion that the payout ratio lies between 70 per cent and 100 per cent. Professor Handley also considers the AER's assumption of full payout to be unrealistic, given the empirical evidence which demonstrates substantially lower payout, and the fact that investors are likely to discount the value of undistributed credits. Professor Handley notes:[921]

> *'An assumption that all credits are distributed in the period in which they are created will likely overstate the value of gamma.'*

Thus the AER's expert advisors would appear to agree that that the payout ratio is less than 100 per cent and hence that assuming 100 per cent payout would lead to an overstatement of gamma. The only issue in the minds of these experts is the extent to which the payout ratio should be below 100 per cent, to reflect the lower value of undistributed credits. For the reasons set out below, CitiPower considers that little value should be assigned to undistributed credits and hence the payout ratio should be significantly below 100 per cent.

The AER's 100 per cent distribution rate implicitly makes two important assumptions:

- that undistributed credits will eventually be distributed; and
- there is no difference in value between distributed and undistributed credits.

In relation to the first assumption, the expert evidence of Mr Feros demonstrates that there are a number of legal and regulatory impediments to distribution of retained credits.[922]

[919] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p26.
[920] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p25.
[921] Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010, p33.
[922] Peter Feros, Review of WACC parameters: Gamma, ETSA Price Reset, 22 June 2009 (Attachment 182 to this Revised Regulatory Proposal).

Additionally, there will be practical impediments to distribution since companies will build up large amounts of retained credits as they only distribute, on average, around 70 per cent of those created in each year. Over time, companies will need to distribute more credits than are actually created in order to distribute retained credits. That the 70 per cent figure is an average and that over time businesses do not generally distribute more credits than are actually created is obvious from the large amounts of retained credits revealed in the ATO statistics – the Handley Report notes that the aggregate balance of retained imputation credits at the end of June 2007 totalled almost $150 billion.[923] It would also explain the tendency for franking account balances to rise over time, noted by McKenzie and Partington.[924]

The AER does not have any empirical evidence to support its assumption that retained credits will be distributed soon after retention. The AER says it is uncertain as to how long firms are likely to retain credits and says it is not aware of any empirical research on the retention period.[925] It is simply assumed that retained credits will be paid out within a one to five year period, when there is in fact no reason to believe that the payout period would necessarily match the regulatory period. The AER also ignores the evidence referred to above which demonstrates the significant constraints on the ability of companies to distribute retained credits in a timely manner.

It is argued by Professor Handley that there are ways in which the value of retained credits may be 'unlocked', including through off-market buy-backs and dividend re-investment plans. However, the use of such mechanisms is likely to be relatively limited and will not significantly affect the overall balance of retained imputation credits. In any case, the use of such mechanisms will already be reflected in the distribution rate studies, including those of Officer and Hathaway (2004) and NERA (2010). These studies consider the total amount of credits distributed by any means (including those referred to by Professor Handley) as a share of credits created.

With respect to the second assumption made by the AER, there appears to be general recognition (including among the AER's experts) that investors will discount the value of undistributed credits. The extent to which discounting occurs will depend on investors' discount rates and the time it takes for retained credits to be distributed (discussed above). Even where the discount rate is low, the discounted value of retained credits will be very small if it takes a long time for retained credits to be distributed.

Given the evidence relating to the rate of retention of credits by companies and the constraints on distribution once these credits are retained, CitiPower considers it likely that investors would heavily discount the value of retained credits. Therefore, the payout ratio should closely reflect the actual distribution rate of 70 per cent which is supported by the empirical evidence and recognised by the AER's expert advisors.

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[923] Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010, p36.
[924] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p27.
[925] AER, Draft Decision, p537.

Finally it should be noted that a payout ratio below 100 per cent would not be inconsistent with the Officer CAPM Framework as the AER claims in its Draft Determination. Professor Officer himself has stated that the Officer CAPM Framework says nothing about the payout ratio, other than to make a simplifying assumption.[926] Such simplifying assumptions are common in academic analysis and are not necessarily intended to reflect reality.

13.2.4.2 Theta

In relation to theta, the AER's consultants have noted the limitations of empirical studies generally, not just the SFG (2009) study of which the AER is critical in the Draft Determination. In light of these limitations, McKenzie and Partington recommend a balanced approach to the evidence on theta, taking into account all available sources of information. McKenzie and Partington state (emphasis added): [927]

> *'Ex-dividend studies and taxation studies however, both have limitations. Ex-dividend studies have substantial measurement and estimation issues and they involve analysis of trades in a restricted window. Taxation studies present results that apply across a broad sweep of investors, but they are subject to measurement problems (this has proven to be less of an issue since the introduction of the simplified tax system). Furthermore, the link between taxation statistics and the market value of imputation credits remains indirect. Therefore, neither type of study is likely to provide an accurate and definitive estimate of gamma on its own.* ***Given the uncertainty surrounding the estimates of gamma, we argue that it is preferable to consider evidence from multiple sources. This means considering results from both types of study and, where multiple studies of the same type are available, considering the results across these studies****.*

McKenzie and Partington summarised this advice, which the AER did not follow in the Draft Determination, in even more explicit terms (emphasis added): [928]

> *'Given the problems inherent in estimating gamma using either taxation or ex-dividend studies, we argue in favour of a balanced approach. Since the best estimation techniques are beset with problems, the most logical approach is to consider the evidence on balance across all available sources. In this respect, the AER's approach of considering both ex-dividend and taxation statistics has merit,* ***but we would recommend a broader range of studies to triangulate the evidence considered by the AER****.'*

In the Draft Determination, the AER appears to have largely ignored this advice from its own consultants. The AER relied on just one dividend drop-off (ex-dividend) study in Beggs and Skeels (2006) and ignored the more recent SFG (2009) study. Moreover, the

[926] Robert R. Officer, Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers, 23 June 2009 (Attachment 185 to this Revised Regulatory Proposal).

[927] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, pp9-10.

[928] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p3.

AER appears to have ignored the limitations of the only tax study it relies on (Handley and Maheswaran (2008)[929]). The limitations of this taxation study and the AER's specific concerns with the SFG (2009) study are addressed in more detail below.

Use of taxation studies

CitiPower considers that tax studies should not be used to calculate the value of theta, since these studies provide no indication as to the value of imputation credits to investors, only the extent to which they are used. However, if the AER is inclined to use tax studies, the findings of these studies should be interpreted with care, given the apparent problems with data used.

(i) Appropriateness of using tax studies

The tax studies relied on by the AER estimate the extent to which imputation credits are used by investors. The result of these studies is a ratio of credits redeemed in a given year to the number of credits created in that year. These studies provide limited information on the value of imputation credits to those investors that redeem them and therefore should not be used to calculate theta.

Tax studies would only be relevant to the value of theta if one assumed that the value of redeemed credits was equal to 100 per cent of their face value. If the value of these credits to redeeming investors was 50 per cent of their face value, then theta would be 50 per cent of the redemption rate.

It is not claimed by the AER's expert advisors that the tax studies provide a reliable estimate of theta, only that these studies provide a reasonable upper bound – in other words theta will be no higher than the estimates produced by the tax studies, but could be significantly lower. The Handley Report refers to the results of tax studies as an 'upper bound' for theta,[930] noting that this term is used in the sense of a theoretical maximum, rather than in a statistical confidence interval sense. McKenzie and Partington note that: [931]

> *'...the link between taxation statistics and the market value of imputation credits remains indirect.'*

These comments by the AER's expert advisors appear to reflect a recognition that the redemption rate of imputation credits will only reflect their value to investors if it is assumed that redeemed credits are fully valued. In practice this may not be a realistic assumption.

CitiPower considers that the AER should not take into account these 'upper bound' estimates from tax studies which are at best indirectly linked to the value of imputation credits. In calculating theta, it is inappropriate to average these theoretical maximum values with the point estimates produced by the dividend drop-off studies.

[929] John C Handley and Krishnan Maheswaran, 'A measure of the efficacy of the Australian imputation tax system', *The Economic Record*, volume 84, number 264, March 2008 (Attachment 186 to this Revised Regulatory Proposal) (**Handley and Maheswaran (2008)**).
[930] Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010, p15.
[931] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p9.

(ii) Risks associated with using tax studies

Notwithstanding the arguments against the use of tax studies (outlined above) if the AER maintains its view that these studies should be used, it should interpret their results with considerable caution. There are a number of issues with both the theoretical bases for these studies and the econometric techniques used.

The study relied on by the AER to derive its 'point estimate'[932] for theta from tax statistics contains various qualifications and assumptions which should induce caution in interpretation. The study by Handley and Maheswaran (2008) produces an imputation credit redemption range of 0.67 to 0.81, from which the AER takes a mid-point of 0.74.[933] However, Handley and Maheswaran (2008) make a number of assumptions and qualifications in their study, which are not interrogated by the AER.

Most obviously, Handley and Maheswaran (2008) do not empirically estimate the redemption rate for imputation credits for the post-2000 period. The authors in fact assume that all credits will be redeemed by individuals and funds over this period, while estimating the redemption rate for non-residents.[934] It is not apparent what the basis for this assumption is, besides mere 'investor rationality'.[935] Nevertheless, it is clear that the estimate of redemption rates for this period cannot be relied on by the AER since it is based on assumption rather than empirical analysis. The use of this assumption in the post-2000 period may explain why the estimate produced by Handley and Maheswaran (2008) is substantially higher for 2001-04, compared to the previous decade (0.81 compared to 0.67).

Further problems are identified by Dr Neville Hathaway in his expert report on the Handley and Maheswaran (2008) study.[936] Dr Hathaway notes that some of the key limitations of this study include:

- the results appear to be contrived as they are based on analyses of data that the authors themselves have created by their assumptions;
- data has been averaged over periods of materially different tax regimes, potentially distorting the results; and
- the methodology used to combine data for different groups introduces the risk of double counting.

In a separate report commissioned by the DNSPs in response to the Draft Determination, Dr Hathaway finds that the taxation data relied on by Handley and Maheswaran appears to be

[932] As noted above, it is incorrect to interpret this as a point estimate for theta, since the tax studies at best provide an upper bound.

[933] John C Handley and Krishnan Maheswaran, 'A measure of the efficacy of the Australian imputation tax system', *The Economic Record*, volume 84, number 264, March 2008 (Attachment 186 to this Revised Regulatory Proposal).

[934] John C Handley and Krishnan Maheswaran, 'A measure of the efficacy of the Australian imputation tax system', *The Economic Record*, volume 84, number 264, March 2008 (Attachment 186 to this Revised Regulatory Proposal), p90 – in the bottom panel of Table 4, the utilisation rate is set to 1 for individuals and funds for each of the years 2001-04 (for earlier years this takes a lower value).

[935] John C Handley and Krishnan Maheswaran, 'A measure of the efficacy of the Australian imputation tax system', *The Economic Record*, volume 84, number 264, March 2008 (Attachment 186 to this Revised Regulatory Proposal), p 86.

[936] Neville Hathaway, Comment on: "A Measure of the Efficacy of the Australian Imputation Tax System" by John Handley and Krishan Maheswaran, July 2008 (Attachment 190 to this Revised Regulatory Proposal).

highly unreliable.[937] Dr Hathaway notes that there are significant unexplained discrepancies in the taxation data and he concludes that this data should not be relied on for making conclusions as to the value of theta.

Given these limitations, the results of the Handley and Maheswaran (2008) study should be interpreted with extreme caution.

Dividend drop-off studies

The DNSPs agree with the recommendation made by McKenzie and Partington for a more 'balanced approach' to the evidence from the available dividend drop-off studies. It is unreasonable for the AER to place so much weight on the findings of Beggs and Skeels (2006), whilst ignoring the more recent evidence from SFG (2009). Although the AER expressed several concerns with the SFG (2009) study in the Draft Determination, these concerns would appear to be unfounded. Each of the AER's specific concerns in relation to the SFG (2009) study is addressed below.

(i) Multicollinearity

The AER have argued that the multicollinearity remains an issue in the dividend drop off study. However, the AER has failed to acknowledge that multicollinearity is no more of an issue for SFG than it is for Beggs and Skeels (2006). McKenzie and Partington's criticisms are generic to dividend drop off studies as a whole and not unique to SFG.

McKenzie and Partington note that multicollinearity is a problem for dividend drop-off studies generally and therefore emphasise the importance of taking a balanced approach to the evidence:[938]

> *'The final area of concern for dividend drop off studies relates to the econometric issues surrounding the estimation of the regression equations. In particular, the issue of multicollinearity dominates as there is a perfect linear relationship between the size of the cash dividend and the franking credit… We conclude that the problems inherent to dividend drop off studies only serve to reinforce our view that a logical approach to estimating gamma is to consider the evidence on balance across all available sources and not rely on any one individual source.'*

Despite this clear advice from McKenzie and Partington, the AER relied in the Draft Determination on just one dividend drop off study, presumably on the assumption that this study is not affected by the same econometric issues as it perceives in the SFG (2009) study. However, the expert report commissioned by the AER demonstrates that this is clearly not the case.

(ii) Reliability of SFG data

The AER has noted that the sampling methodology developed by Field implies a range of 6.2 – 16.7 per cent of 'unacceptable' observations. Although this may be the case the AER

[937] Neville Hathaway, Imputation Credit Redemption: ATO data 1988-2008, July 2010 (Attachment 189 to this Revised Regulatory Proposal).

[938] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p5.

has given no consideration to the materiality of the 'unacceptability' and its likely effect on the results.

SFG have adopted a modified version of the Cook's D procedure which removed influential and unreliable observations. While unreliable observations may remain, any such observations would not be influential – that is, they would have little impact on the results.

Despite the AER's suggestion that the sampling exercise was of no useful purpose, what the sampling procedure has clearly shown is that the removal of any further observations has an immaterial effect on the results, with SFG's results being incredibly stable. After a re-calibration of the estimation following the removal of a handful of observations there was a change at the third decimal point.[939]

As a final observation, the SFG study has been subject to a much higher degree of scrutiny than the Beggs and Skeels (2006) study. Unlike the Beggs and Skeels (2006) study, the SFG data has been made available for comment and SFG have responded to any concerns of the AER. There has been no such interrogation of the Beggs and Skeels study notwithstanding that the paper was peer reviewed. It is also relevant that this paper was written to examine structural breaks in the tax system not give an estimate for theta per se. Even Skeels himself has stated that in his opinion the SFG estimate is currently the best estimate available.[940]

(iii) Use of Cook's D Statistic

The criticisms in the Draft Determination surrounding the use of Cook's D Statistic have already been addressed by Skeels and SFG. SFG modified the Cook's D Statistic to identify the top one per cent of observations and then only exclude those which were unreliable. This application is not arbitrary and is justified on economic grounds.

The AER has provided no examples of the types of decisions it may consider to be 'jointly influential' or how this may manifest itself in the results. This is merely an allusion to a possible concern, but is not supported by anything other than an assertion of the AER.

Skeels has reviewed this modified approach to the use of the Cook's D Statistic and commented that it is a reasonable trade off in terms of efficiency and accuracy.[941] Further, this statistical measure should also be considered in light of the other diagnostics and checks performed by SFG including the standard errors of the results and the fact that the sampling exercise shows significant stability in the SFG estimate.

(iv) Zero and negative drop-offs

McKenzie and Partington have criticised the data in the SFG analysis for containing a number of zero and negative drop-offs.

[939] SFG, Response to the AER draft determination in relation to gamma, 13 January 2010 (Attachment 187 to this Revised Regulatory Proposal), pp 17 – 18.

[940] Christopher L Skeels, A Review of the SFG Dividend Drop-Off Study – A Report prepared for Gilbert and Tobin, 28 August 2009 Attachment 188 to this Revised Regulatory Proposal), p 31.

[941] See, Christopher L Skeels, Response to AER Questions, 21 September 2009 (Attachment 191 to this Revised Regulatory Proposal), p 6 – 8.

McKenzie and Partington stated that the number of zero drop-off observations in the SFG study is 'higher than expected'.[942] However, there is simply no evidence provided to support this assertion. There is also no evidence as to the number of zero and negative drop-offs in the Beggs and Skeels (2006) study. The AER has not tested this aspect of the study on which it relies and it is quite possible that this study has a similar number of such observations.

In relation to negative drop-offs, McKenzie and Partington have argued that negative and zero drop-offs may bias the sample and should be removed.[943] However, this argument ignores the fact that the negative or zero-drop off is caused by a purely random event and there is accordingly no basis to remove it from the sample. In fact, excluding observations in this arbitrary manner would inevitably bias the results. SFG, in its report in response to the Draft Determination, concludes:[944]

> *'it would be wrong to routinely omit zero or negative drop-off observations. Such observations should only be omitted if they are erroneous, and there is no evidence of that.'*

(v) Consistency in AER parameter estimation

As noted in the SFG report in response to the Draft Determination, the AER has also failed to address the two inconsistent assumptions it makes when deriving the return on capital:[945]

- the AER's empirical estimates of theta (and consequently gamma) are conditional on an estimated value of cash dividends of 80 cents per dollar; and
- the AER's estimate of the required return on equity using the Officer CAPM Framework is conditional on cash dividends being valued at 100 cents per dollar.

It is inconsistent and wrong for the AER to use two different values for the same parameter when estimating the return on capital. The Tribunal has previously recognised the importance of maintaining the mathematical integrity of the Officer CAPM framework when estimating the WACC in the Application by GasNet Australia (Operations) Pty Ltd.[946] The AER must address this issue and cannot maintain its previous approach in violation of the principle set out in the Application by GasNet Australia (Operations) Pty Ltd.

(vi) Methodological issues

In the Draft Determination, the AER takes an average of the values from Beggs and Skeels (2006) and Handley and Maheswaran (2008) to derive its value of theta. The AER argues that this is a valid approach, since both of these values represent point estimates. The AER

[942] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p38.
[943] Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p38.
[944] SFG, Issues relating to the estimation of gamma, 15 July 2010 (Attachment 192 to this Revised Regulatory Proposal), p18.
[945] SFG, Issues relating to the estimation of gamma (Attachment 192 to this Revised Regulatory Proposal), 10 July 2010.
[946] *Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6 (Attachment 193 to this Revised Regulatory Proposal).

considers the value from Handley and Maheswaran (2008) to represent an 'upper value within a range of reasonable point estimates' and not an upper bound for theta.[947]

This approach to estimating theta is methodologically flawed, since it takes an average of a point estimate (from the Beggs and Skeels (2006) dividend drop-off study) and an upper bound estimate (from the taxation study). This implies that the AER's estimate of theta will be upwardly biased.

Tax statistics do not contain any information about the value of an imputation credit in the sense of what an investor would pay for it. The tax studies will only provide an upper bound for theta since there is an implicit assumption that credits are fully valued by the investors that redeem them. If credits are not fully valued, then the value of theta will be less than what is implied by the tax studies. This point is noted in the SFG report in response to the Draft Determination[948] and also by the AER's own consultants.

13.2.4.3 Conclusions

CitiPower submits that a value of gamma of 0.65 is inappropriate. The AER's reasoning in support of this value for gamma is deficient in a number of areas, including the following, and there is persuasive evidence to depart from the value for gamma set out in the SoRI.

- The AER has ignored the weight of empirical evidence which demonstrates that the distribution rate is not 100 per cent, and is in fact likely to be around 70 per cent. This includes the expert reports commissioned by the AER itself which acknowledge that the distribution rate is below 100 per cent.
- The AER continues to assert that a 100 per cent distribution rate is consistent with the Officer CAPM Framework, even though this has been denied by Professor Officer himself.
- The AER has relied on the tax study by Handley and Maheswaran (2008) to derive an 'upper bound' for theta, despite apparent deficiencies in this study. The AER also appears to have misinterpreted the results of this study in deriving its 'upper bound'.
- The AER has relied on just one dividend drop-off study to estimate theta, notwithstanding the advice of its experts to take a more 'balanced approach'. The AER continues to disregard the more recent SFG (2009) study, despite expert evidence to suggest that this study is at least as reliable as the Beggs and Skeels (2006) study.
- The AER's approach to estimating theta as an average of a point estimate and an upper bound is methodologically flawed.

Taking a more balanced approach to the evidence (including consideration of the empirical evidence in relation to the distribution rate and the SFG (2009) study in relation to theta) would yield a gamma value that is significantly below 0.5. Therefore adopting a value for gamma of 0.5 is conservative, and is consistent with the significant body of empirical evidence and expert opinion.

[947] AER, Draft Determination, pp551-552.
[948] SFG, Issues relating to the estimation of gamma, 15 July 2010 (Attachment 192 to this Revised Regulatory Proposal), pp25-26.

13.2.5 CitiPower's Revised Regulatory Proposal

CitiPower does not make any amendments to its Initial Regulatory Proposal in relation to the value of gamma.

CitiPower maintains that, in light of the underlying criteria, a material change in circumstances since the date of the SoRI or another relevant factor makes the value for gamma set out in the SoRI inappropriate. CitiPower considers that the appropriate value for gamma is 0.5.

13.2.6 Regulatory Information Notice response

Paragraphs 2.3 and 2.4 of the Further RIN - require CitiPower to:

- identify each proposed departure from a WACC parameter set out in the SoRI; and
- for each such departure, provide all supporting consultants reports and documents.

CitiPower proposes departures from the value for gamma set out in the SoRI. As explained in section 13.2.4 above, CitiPower considers that the appropriate value for gamma is 0.5.

Attached to this Revised Regulatory Proposal are the supporting consultant reports and other relevant documents related to this proposed departure from the SoRI, including the underlying data, assumptions, calculations, modelling code, estimation outputs from any regression results and results of any statistical tests.

13.3 Change in tax laws and other taxation issues

13.3.1 Rules requirements

Transitional provisions of specific application to Victoria are set out in clause 11.17 of the Rules. Clause 11.17.2(b) requires that when calculating the estimated cost of corporate income tax for the 2011-15 regulatory control period, the AER must adopt the same taxation values, classification of assets and method of depreciation adopted by the ESCV in the ESCV's 2006-10 EDPR. However, clause 11.17.2(c) provides that the AER may depart from these methods of asset classification or depreciation *'to the extent required by changes in the taxation laws or rulings given by the Australian Taxation Office'*.

13.3.2 CitiPower's Initial Regulatory Proposal

In the Initial Regulatory Proposal, CitiPower did not propose any departures from the methods adopted by the ESCV as a result of changes in taxation laws or rulings by the ATO.

13.3.3 AER's Draft Determination

In the Draft Determination, the AER made the following departures from the methods adopted by the ESCV:

- as a result of amendments to Division 40 of the Income Tax Assessment Act 1997 (Cth) to reflect increases in the deductions for the decline in value of depreciating assets, the AER amended CitiPower's tax roll forward calculations to apply higher depreciation rates; and

- as a result of announcements by the Commonwealth Government that it intends to reduce the corporate tax rate to 29 per cent for the 2013-14 financial year and to 28 per cent for the 2014-15 financial year, the AER has modified the statutory corporate income tax rate.[949]

The AER also included tax depreciation of equity raising costs, calculating tax depreciation on a straight line basis applying a tax rate of 20 per cent.

13.3.4 CitiPower's response to the AER's Draft Determination

CitiPower adopts the AER's amendments in the Draft Determination, except that CitiPower notes that the Government announced on 2 July 2010 that the company tax rate will continue to be cut to 29 per cent from 2013-14 but will not be further reduced to 28 per cent in 2014-15.[950]

Accordingly, the AER must amend its approach in the Draft Determination to reflect the latest Government policy and the removal of the proposed reduction of the corporate income tax rate to 28 per cent.

CitiPower also notes that other tax changes that were announced by the Government at same time as the original proposed changes to the corporate income tax rate include an increase in the superannuation guarantee rate to 12 per cent, with the increases starting on 1 July 2013.[951] For consistency with its approach to the company tax rate changes, the AER must also allow an opex step change to address this announced change to the superannuation guarantee rate.

13.3.5 CitiPower's Revised Regulatory Proposal

CitiPower amends its Initial Regulatory Proposal to adopt the AER's approach in the Draft Determination in relation to changes in tax laws and tax depreciation of equity raising costs, except that it proposes that the company tax rate reduction should be amended to reflect the Government's announcements that the proposed reduction to 28 per cent will not occur.

CitiPower's proposed estimated cost of corporate income tax is set out in Table 13.1.

	$m (nominal)				
	2011	2012	2013	2014	2015
Estimated cost of corporate income tax	4.2	4.6	5.5	5.9	6.9

Table 13.1 Estimated cost of corporate income tax

949 AER, Draft Determination, p555.

950 Media release by Prime Minister entitled 'Breakthrough agreement with industry on improvements to resources taxation', 2 July 2010, http://www.pm.gov.au/node/6868 (Attachment 195 to this Revised Regulatory Proposal). Australian Government Fact Sheet, Cutting the Company Tax Rate (accessed 8 July 2010) (Attachment 194 to this Revised Regulatory Proposal).

951 Australian Government Fact Sheet, Superannuation – Increasing the superannuation guarantee rate to 12 per cent, (Attachment 131 to this Revised Regulatory Proposal).

14. EFFICIENCY CARRYOVER AMOUNTS FOR 2006-10

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 13 of the Draft Determination regarding efficiency carryover amounts for 2006-10.

This Chapter does not address Chapter 14 of the Draft Determination regarding the EBSS. The EBSS is addressed in Chapter 15 of this Revised Regulatory Proposal.

14.1 Summary of key points

CitiPower does not accept the AER's decision to reject CitiPower's proposed adjustments to the 2006-10 carryover amounts to exclude uncontrollable costs (superannuation costs and GSL payments) and remove the ESCV's 0.39 per cent partial productivity factor adjustment. That decision is incorrect, based in part on errors of law, inconsistent with the NEL and Rules and inconsistent with the AER's decisions and reasons in other parts of the Draft Determination.

CitiPower does not accept the amount of the adjustments that the AER made in relation to provisions, licence fees or network growth when calculating the 2006-10 carryover amounts. Those decisions are incorrect and based on errors of fact.

CitiPower does not accept the AER's decision to reject CitiPower's proposed NPV approach for determining the 2006-10 carryover amount, which would have set CitiPower's carryover amount at zero instead of a negative amount. That decision is unreasonable and inconsistent with the ESCV's reasoning in the ESCV's 2006-10 EDPR where it adopts an NPV approach for reasons that are equally applicable to the AER's decision, and is inconsistent with the NEO, the revenue and pricing principles and the objectives of the ECM and the EBSS.

14.2 Rules requirements

The AER's only power to bring to account efficiency carryover amounts from a previous regulatory period arises under clause 6.4.3(a)(6) of the Rules.

Clause 6.4.3(a) of the Rules provides:

> 'Building blocks generally
>
> *The annual revenue requirement for a Distribution Network Service Provider for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks are:*
>
> *(1) indexation of the regulatory asset base – see paragraph (b)(1); and*
>
> *(2) a return on capital for that year – see paragraph (b)(2); and*
>
> *(3) the depreciation for that year – see paragraph (b)(3); and*
>
> *(4) the estimated cost of corporate income tax of the provider for that year – see paragraph (b)(4); and*
>
> *(5) the revenue increments or decrements (if any) for that year arising from the application of the* efficiency benefit sharing scheme*, the* service target performance incentive scheme *and the* demand management incentive scheme *– see paragraph (b)(5); and*

(6) *the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous* regulatory control period – *see paragraph (b)(6); and*

(7) *the forecast operating expenditure for that year – see paragraph (b)(7).'*

Clause 6.4.3(b)(6) provides:

> *'the other revenue increments or decrements referred to in paragraph (a)(6) are those that are to be carried forward to the current* regulatory control period *as a result of the application of a control mechanism in the previous* regulatory control period *and are apportioned to the relevant year under the distribution determination for the current* regulatory control period.'.

14.3 Exclusion of uncontrollable costs and removal of efficiency adjustments

14.3.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower proposed that adjustments to the ESCV's operating expenditure benchmarks or CitiPower's actual opex figures were required for the purposes of the 2006-10 efficiency carryover calculation in relation to:

- superannuation costs in 2006-09;
- GSL payments in 2006-09; and
- removal of the ESCV's 0.39 per cent partial productivity factor adjustment.[952]

The basis for these adjustments is that they are consistent with:

- the approach taken by the ESCV in the ESCV's 2006-10 EDPR for calculation of carryover amounts arising from 2001-05, which adopted a principle of requiring adjustments so that there can be a 'like-for-like comparison' between the opex benchmarks and actual opex;
- the ORG Appeal Panel Decision in relation to the ORG's 2001-05 EDPR, which required adjustments in calculating the carryover amounts arising from the previous period so that the benchmarks and actual opex figures were comparable and an accurate measure of efficiency; and
- the AER's EBSS Guideline, which provides for adjustments for uncontrollable costs and pass through events.[953]

CitiPower also provided an expert report from NERA, which stated that in order to be consistent with the NEO, the revenue and pricing principles and clause 6.5.8(c) of the Rules, efficiency gains or losses from the 2006-10 period should only be carried over by the AER if the AER adjusts the carryover amounts to remove the effects of uncontrollable costs and the ESCV's productivity adjustment.[954]

[952] Initial Regulatory Proposal, pp250-256.
[953] Initial Regulatory Proposal, pp250-256.
[954] NERA, Treatment of Accrued Carryovers in the 2011-15 Regulatory Period, 22 December 2009, provided by CitiPower to the AER on 23 December 2009 (Previously provided to the AER under cover of an email to B Burkitt, Director Network Regulation South Branch AER from B Cleeve, Manager Price Review, CitiPower and Powercor Australia of the same date).

14.3.2 AER's Draft Determination

In the Draft Determination, the AER rejected all of CitiPower's proposed adjustments.

While the AER's explicit consideration of CitiPower's proposed adjustments is set out in section 13.5.5 of the Draft Determination, the AER's reasons for its decision to reject all of those adjustments appear to also be set out, in part, in section 13.5.2 of the Draft Determination in relation to Powercor Australia's 2001-05 accrued negative carryover. Accordingly, it is necessary to identify and consider all of the AER's reasoning of potential applicability to CitiPower's proposed adjustments to properly understand the AER's reasons for rejecting CitiPower's proposed adjustments.

The stated reasons for the AER's decision to reject all of those adjustments appear in section 13.5.5 of the Draft Determination under the sub-heading 'AER conclusion'. These stated reasons were that:

- the ESCV did not explicitly allow for adjustments to exclude uncontrollable costs in its ECM to apply to the Victorian DNSPs for the 2011–15 regulatory control period;
- the Victorian DNSPs did not raise the issue of uncontrollable costs in the ECM in the ESCV's 2006-10 EDPR and have previously criticised any attempts to distinguish between management induced efficiencies and windfall gains; and
- any adjustment for windfall losses would require a consideration of windfall gains (however, given the information asymmetry, the DNSPs may not identify windfall gains).955

The AER also made the following additional observations in section 13.5.5 in considering CitiPower's proposed adjustments:

- The ORG Appeal Panel Decision rejecting the ORG's decision not to make adjustments to Powercor Australia's 1995-99 costs associated with network growth in calculating the carryover amounts arising from the 1995-99 period did not provide any expectation that uncontrollable costs would be excluded from the carryover amounts for 2011-15 because the decision was limited to growth adjustments in the calculation of carryover amounts.[956]
- In its EBSS Final Decision, the AER requires that the exclusion of cost categories from the calculation of the EBSS carryover amounts arising in the 2011-15 and subsequent regulatory control periods be determined on an ex ante basis to preserve the ex ante incentives established by the EBSS. However, the ESCV's ECM as detailed in the ESCV's 2006-10 EDPR did not specify any ex ante adjustments to the ESCV benchmark allowance for uncontrollable costs.[957]

In addition, it appears that some of the AER's reasoning set out in section 13.5.2 of the Draft Determination in relation to Powercor Australia's 2001-05 accrued negative carryover may have influenced its decision in section 13.5.5 to reject CitiPower's proposed adjustments. The AER reasoning set out in section 13.5.2 of the Draft Determination that would appear to have applicability to CitiPower's proposed adjustments includes the following:

[955] AER, Draft Determination, p594.
[956] AER, Draft Determination, p592.
[957] AER, Draft Determination, pp592-3.

- The AER is required by the ESCV's 2006-10 EDPR, the EBSS Final Decision and the AER's powers under the NEVA to enforce the ESCV's 2006-10 EDPR to apply the ESCV's ECM without revisiting the design of the ESCV's ECM and/or making any ex post adjustments to the carryover amounts calculated in accordance with that ECM.[958]

- In any event, it is not appropriate to revisit the design of the ESCV's ECM and/or make ex post adjustments to the carryover amounts calculated in accordance with that ECM given that incentives are determined on an ex ante basis and the AER cannot influence Powercor Australia's past behaviour.[959] In this context, the AER noted that:
  - neither Powercor Australia nor the other DNSPs raised any issues at the time of the ESCV's 2006-10 EDPR regarding the ORG's and ESCV's approach to:
    - establishing the base year forecast for the 2001-05 opex benchmarks;
    - the adjustment to Powercor Australia's base year for establishing the 2006-10 opex benchmarks; and
    - the inclusion of uncontrollable costs in the measurement of efficiency gains and losses;[960] and
  - in establishing the ECM, the ORG and the ESCV did not design the ECM such that uncontrollable costs should be identified and excluded from the carryover amounts.[961]

- It is not appropriate to apply the requirements of the NEL and Rules retrospectively to the ESCV's ECM.[962]

- The requirements of the Tariff Order under which the ESCV's ECM was made are similar to the Rules requirements and included in particular a requirement to have regard to ensuring a fair sharing of gains and losses between DNSPs and customers. The AER's inference from this statement is that it follows that the ESCV's ECM and associated approach to setting the benchmark allowance for 2006-10 was consistent with the Rules, the NEO and the revenue and pricing principles.[963]

Accordingly, while the AER's stated reasons for rejecting all of CitiPower's proposed adjustments were limited to the 3 reasons set out at the beginning of this section, CitiPower understands that the AER's reasons for rejecting those proposed adjustments were as follows:

- The ESCV's ECM as detailed in the 2 ESCV's 006-10 EDPR did not specify any ex ante adjustments to the ESCV benchmark allowance of the kind now proposed by CitiPower.

- The AER is required by the ESCV's 2006-10 EDPR, the EBSS Final Decision and the AER's powers under the NEVA to enforce the ESCV's 2006-10 EDPR to apply the ESCV's ECM without revisiting the design of the ESCV's ECM and/or making any ex post adjustments to the carryover amounts calculated in accordance with that ECM.

958 AER, Draft Determination, pp570-2.
959 AER, Draft Determination, p575.
960 AER, Draft Determination, p575.
961 AER, Draft Determination, p577.
962 AER, Draft Determination, p576.
963 AER, Draft Determination, pp576 & 578.

- In any event, it is not appropriate to revisit the design of the ESCV's ECM and/or make ex post adjustments to the carryover amounts calculated in accordance with that ECM because:
  - incentives are determined on an ex ante basis and the AER cannot influence CitiPower's past behaviour;
  - CitiPower did not have any expectation that its proposed adjustments would be made in calculating the carryover amounts for 2011-15 arising from the 2006-10 period because:
    - the ESCV's ECM as detailed in the ESCV's 2006-10 EDPR did not specify any ex ante adjustments to the benchmark allowance of the kind now proposed by CitiPower; and
    - the ORG Appeal Panel Decision rejecting the ORG's decision not to make adjustments to Powercor Australia's 1995-99 costs in calculating the carryover amounts arising from the 1995-99 period was limited to growth adjustments;
  - the Victorian DNSPs did not raise the issue of uncontrollable costs in the ECM in the ESCV's 2006-10 EDPR and have previously criticised any attempts to distinguish between management induced efficiencies and windfall gains; and
  - any adjustment for windfall losses would require a consideration of windfall gains (however, given the information asymmetry, the DNSPs may not identify windfall gains).
- The requirements of the NEL and the Rules cannot justify the making of any ex-post adjustments to the carryover amounts calculated in accordance with the ECM because the NEL and the Rules cannot be applied retrospectively to the ESCV's ECM.
- In any event, the ESCV's ECM and associated approach to setting the benchmark allowance for 2006-10 was consistent with the Rules, the NEO and the revenue and pricing principles because the requirements of the Tariff Order under which the ESCV's ECM was made are similar to the Rules requirements.

14.3.3 CitiPower's response to the AER's Draft Determination

The AER's decision in the Draft Determination to reject CitiPower's proposed adjustments is incorrect, based in part on errors of law, inconsistent with the NEL and Rules and inconsistent with the AER's decisions and reasons in other parts of the Draft Determination.

CitiPower maintains that these adjustments are required for consistency with:

- the approach taken by the ESCV in the ESCV's 2006-10 EDPR for calculation of carryover amounts arising from 2001-05, which adopted a principle of requiring adjustments so that there can be a 'like-for-like comparison' between the ex post opex benchmarks and actual opex;
- the ORG Appeal Panel Decision in relation to the ORG's 2001-05 EDPR, which required ex post adjustments in calculating the carryover amounts arising from the previous period so that the benchmarks and actual opex figures were comparable and an accurate measure of efficiency;

- the AER's EBSS Guideline, which provides for adjustments for uncontrollable costs and pass through events; and
- the NEO and the revenue and pricing principles.

The remainder of this section addresses each of the AER's apparent reasons for rejecting CitiPower's proposed adjustments.

14.3.3.1 AER reason 1: The ESCV's ECM did not specify any ex ante adjustments of the kind proposed

The AER's first stated reason for rejecting these adjustments is that the ESCV did not explicitly allow for these adjustments in its ECM to apply to the Victorian DNSPs for the 2011–15 regulatory control period.[964]

The ECM in the ESCV's 2006-10 EDPR did not explicitly allow for adjustments in relation to the specific costs that CitiPower is seeking. However, as discussed in more detail below, the ESCV did adopt a general principle that adjustments must be made so that actual opex can be compared with the original opex benchmarks on a 'like for like' basis. In this regard, CitiPower's proposed adjustments are allowed for in, and are consistent with, the ESCV's ECM.

There are several reasons why *'the ESCV did not explicitly allow for these adjustments in its ECM to apply to the Victorian DNSPs for the 2011–15 regulatory control period'*:

- The ESCV did not explicitly allow for any adjustments in its ECM for the amounts to be carried over to 2011-15, as it was not within the ESCV's powers to determine the amounts that will be carried over into 2011-15.
- The ESCV's ECM was not designed in a way that contemplated that adjustments would be determined at the commencement of the regulatory period. This is a significant difference between the ESCV's ECM and the AER's EBSS Guideline. Under the ECM in the ESCV's 2006-10 EDPR, carryover amounts were only determined at the end of a regulatory period by application of the 'like for like' principle. As part of determining those amounts, various adjustments could be made at the end of the period. Those adjustments were not specified in the determination prior to the commencement of the period.965
- The same approach applied in the ORG's ECM for 2001-05 regulatory periods. Under the ORG's 2001-05 EDPR and the ORG Appeal Panel Decision,966 adjustments to carryover amounts for the preceding period were determined by the ORG at the end of that regulatory period.967 Adjustments to the carryover amounts for the forthcoming regulatory period were not explicitly set out in the ORG's 2001-05 EDPR or the ORG Appeal Panel Decision.
- Under both the ESCV's ECM and the ORG's ECM, adjustments were made at the end of a regulatory period in relation to matters that were not explicitly allowed for, or even contemplated, in the relevant determination at the commencement of the

[964] AER, Draft Determination, p594.
[965] See for example, ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), pp419-421.
[966] ORG Appeal Panel Decision (Attachment 214 to this Revised Regulatory Proposal).
[967] See for example ORG, ORG's 2001-05 EDPR, Volume 1, Chapter 5 (Attachment 213 to this Revised Regulatory Proposal), p100.

regulatory period. For example, the ESCV in the ESCV's 2006-10 EDPR made adjustments to CitiPower's carryover amounts for the 2001-05 regulatory period to account for changes in capitalisation policies, movements in provisions and removal of related party margins.968 None of those adjustments were explicitly allowed for in, or contemplated by, the ORG in the ORG's 2001-05 EDPR.

In any event, whether the ESCV explicitly allowed for these adjustments in its ECM in the ESCV's 2006-10 EDPR is not determinative of whether the AER should make these adjustments in its Final Determination. The AER's decision must be made in accordance with the requirements of clause 6.4.3(a)(6), the NEO and the revenue and pricing principles. As discussed further below, the AER erred in concluding that the application of the NEO and these requirements and principles to the calculation of carry over amounts to be applied in 2011-15 would involve an impermissible retrospective application of those matters. The AER's Draft Determination on these adjustments does not refer to the NEO or revenue and pricing principles or consider whether its decision is consistent with those matters. The AER cannot ignore those matters and simply base its decision on whether the ESCV referred to a matter in the ESCV's 2006-10 EDPR.

14.3.3.2 AER reason 2: The AER is required by the ESCV's 2006-10 EDPR, the EBSS Guideline and the NEVA to apply the ESCV's ECM without change

The AER appears to consider that the ESCV's 2006-10 EDPR, the EBSS Final Decision and the AER's powers under the NEVA to enforce the ESCV's 2006-10 EDPR require the AER to apply the ECM as set out in the ESCV's 2006-10 EDPR.

This view is based on the same errors of law that the AER makes in section 13.5.2 of the Draft Determination in relation to the 2001-05 negative carryover. In that section, the AER took the view that it was required to apply the ECM as set out in the ESCV's 2006-10 EDPR and is not able to depart from the ESCV's ECM.

As explained in Powercor Australia's Revised Regulatory Proposal, the AER's reasoning and conclusions on that issue are based on several errors of law. It appears likely that those errors have also influenced the AER's reasoning in relation to CitiPower's proposed adjustments, in that the AER appears to have been influenced by a view that it is required to apply the ECM as set out in the ESCV's 2006-10 EDPR. That view is not correct. None of the ESCV's 2006-10 EDPR, the EBSS Guideline or the NEVA can authorise the AER to act in a way that is beyond its powers under the NEL and Rules.

14.3.3.3 AER reason 3: It is not appropriate to revisit the design the ESCV's ECM and/or make ex post adjustments to the carryover amounts calculated in accordance with the ECM

The AER appears to consider that it is not appropriate to revisit the design of the ESCV's ECM and/or make ex post adjustments to the carryover amounts calculated in accordance with the ECM because:

- the AER cannot affect past behaviour;

[968] ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), pp419-420.

- CitiPower did not have any expectation that its proposed adjustments would be made;
- the Victorian DNSPs did not raise the issue of uncontrollable costs during the ESCV's 2006-10 EDPR process; and
- any adjustment for windfall losses would also require a consideration of windfall gains.

CitiPower accepts that the AER's calculation of carry over amounts arising in 2006-10 and to be applied in 2011-15 cannot affect its behaviour in 2006-10.

However, CitiPower rejects the AER's conclusion that CitiPower did not have any expectation in 2006-10 that its proposed adjustments would be made. To the contrary, throughout the 2006-10 period, CitiPower operated on the basis of an expectation that those adjustments required by the application of the ESCV ECM's 'like for like' principle would be made in the calculation of the carryover amounts arising from that period. As CitiPower's proposed adjustments involve an application of the ESCV ECM's 'like for like' principle, it follows that the making of CitiPower's proposed adjustments is consistent with CitiPower's expectations during the 2006-10 period and is required if the AER is to preserve regulatory certainty and the incentives under incentive mechanisms to apply in future periods.

The AER's statement that making CitiPower's adjustments is inconsistent with the ex ante incentives under the ESCV's ECM fundamentally misunderstands the nature of the ESCV's ECM. Unlike the AER's EBSS, the ESCV's ECM (and the ORG's ECM prior to that) never sought to define the adjustments up front and always allowed adjustments at the end of the regulatory period on the basis of the application of the 'like for like' principle.

CitiPower's proposed adjustments do not involve revisiting the design of the ESCV's ECM. Instead, they continue the practice of the ESCV (and prior to that, the ORG Appeal Panel) of making adjustments on an ex post basis at the end of a regulatory period based on the 'like for like' principle.

As explained above, the ESCV made adjustments at the end of a regulatory period in relation to matters that were not allowed for or contemplated in the ORG's 2001-05 EDPR. In particular, in the ESCV's 2006-10 EDPR, the ESCV applied the 'like for like' principle to make adjustments in relation to changes in capitalisation policies, movements in provisions and removal of related party margins in calculating the ECM carryover amounts arising in the 2001-05 period to be carried over into the 2006-10 period. None of these matters were provided for by the ORG's 2001-05 EDPR, nor were they raised by CitiPower in submissions during the ORG's 2001-05 EDPR process.

This need to make ex post adjustments was confirmed by the ORG Appeal Panel Decision. In the Draft Determination, the AER stated that the ORG Appeal Panel Decision was only related to growth adjustments and has no application to CitiPower's proposed adjustments. That is not correct. The ORG Appeal Panel Decision establishes a general principle that adjustments are required so that the benchmarks and actual expenditure can be compared, and that if such adjustments are not made then the ECM is not an accurate measure of efficiency.

For example, the ORG Appeal Panel states: [969]

> *'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.*
>
> *...*
>
> *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 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 ESCV's 2006-10 EDPR, the ESCV accepted that the Appeal Panel decision was authority for the broader 'like for like' comparison principle. For example, the ESCV stated: [970]

> *'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.*
>
> *...*
>
> *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.*
>
> *...*
>
> *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.*

[969] ORG Appeal Panel Decision (Attachment 214 to this Revised Regulatory Proposal), pp5-9.
[970] ESCV, EDPR 2006-10, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), pp159 and 419.

It is therefore consistent with the ESCV's ECM and the ORG Appeal Panel Decision for the AER to make adjustments to the 2006-10 carryover amounts as proposed by CitiPower, and as made by the AER in relation to other matters in section 13.5.4 of the Draft Determination.

On the basis of these previous statements by the ESCV and ORG Appeal Panel, it is also entirely reasonable for CitiPower to have had an expectation at the commencement of the 2006-10 regulatory period, and during that period, that adjustments would be made in the Final Determination in calculating the carryover amounts arising from 2006-10 to apply the 'like for like' principle and remove any costs that were not included in the ESCV's benchmarks.

It appears that the AER may be seeking to impose the model of its EBSS, with its adjustments for uncontrollable costs that are defined in advance, on to the ESCV's ECM. The ESCV's ECM never operated in that manner and it is inappropriate to disregard the different characteristics of the ESCV's ECM in identifying the ex ante incentives created by that ECM.

The EBSS model can be applied going forward, but for the purposes of determining 2006-10 carryover amounts for the Final Determination, the AER must continue to apply the ESCV's 'like for like' principle and allow adjustments to the carryover amounts. Doing so will not undermine regulatory certainty in the ECM or the EBSS. Instead, it will promote regulatory certainty by continuing the approach adopted by the ESCV, and which CitiPower legitimately expected that the AER would apply in the Final Determination.

Making these adjustments will not undermine regulatory certainty in the EBSS, as this is solely a transitional matter for the Final Determination. The EBSS's model of defining the adjustments up front for 2011 onwards has been accepted by the DNSPs and will avoid this issue arising in future determinations.

The AER's states that *'the Victorian DNSPs did not raise the issue of uncontrollable costs in the ECM in the 2006 EDPR and have previously criticised any attempts to distinguish between management induced efficiencies and windfall gains'*.[971] It is irrelevant whether the Victorian DNSPs raised this issue during the process leading up to the ESCV's 2006-10 EDPR.

This issue was not raised during the ESCV's 2006-10 EDPR process because CitiPower understood that adjustments would be made at the end of the 2006-10 period based on the application of the 'like for like' principle. As noted above, during the ESCV's 2006-10 EDPR process, adjustments were made by the ESCV in calculating the carryover amounts arising in 2001-05 to be applied in 2006-10 based on the same underlying principle that actual opex must be able to be compared with the original opex benchmarks on a 'like for like' basis. CitiPower's proposed adjustments are simply an application of this principle that was accepted by the ESCV in the ESCV's 2006-10 EDPR.

[971] AER, Draft Determination, p594.

As noted by the ESCV in the ESCV's 2006-10 EDPR, that 'like for like' principle has its genesis in the ORG Appeal Panel Decision. The ORG Appeal Panel decision related to a successful challenge to the ORG's refusal to allow adjustments as part of the efficiency carryover calculation to ensure that actual opex was measured on a consistent basis to the original opex benchmarks.

There is accordingly a clear history of the Victorian DNSPs proposing adjustments based on the 'like for like' principle in previous price reviews, and the relevant regulator accepting those adjustments. The fact that those adjustments related to different matters to the proposed adjustments, even though they were based on the same underlying principle, is not a valid reason for rejecting the proposed adjustments.

The AER also states that *'any adjustment for windfall losses would require a consideration of windfall gains (however, given the information asymmetry, the DNSPs may not identify windfall gains)'*.[972]

This statement by the AER is not supported by any evidence. The AER has no evidence that any windfall gains would arise if it did not make other adjustments. In addition, the AER's assertion that there is an information asymmetry that prevents it obtaining this information is inconsistent with the AER's extensive information gathering powers conferred by the NEL and its exercise of those powers (as well as its voluntary information gathering powers) in this review process. CitiPower does not consider that adjustments for windfall gains would be required if CitiPower's proposed adjustments are made.

14.3.3.4 AER reason 4: The NEL and Rules cannot be applied retrospectively

The AER states that it is not appropriate to apply the requirements of the NEL and Rules retrospectively to the ESCV's ECM.[973]

This comment by the AER misunderstands the concept of retrospectivity.

The presumption against retrospectivity prevents the law applying to facts or events that have already occurred in such a way as to affect rights or liabilities that the law had defined by reference to those past events. However, a distinction must be made between legislation having a prior effect on past events and legislation basing future action on past events. The latter does not constitute retrospectivity.[974]

This distinction was explained by the Supreme Court of Victoria as follows: [975]

> *'[The] principle is not concerned with the case where the enactment under consideration merely takes account of antecedent facts and circumstances as a basis for what it prescribes for the future, and it does no more than that.'*

This comment by the AER misunderstands the concept of retrospectivity and, accordingly, involves error of law. The decision that the AER is required to make is a decision under

[972] AER, Draft Determination, p594.
[973] AER, Draft Determination, p576.
[974] D.C. Pearce, Statutory Interpretation in Australia, 6th edition, 2006, Chapter 10 (Attachment 219 to this Revised Regulatory Proposal), p309.
[975] *Robertson v City of Nunawading* [1973] VR 819, at 824.

clause 6.4.3(a)(6) in relation to the amount of the revenue increments or decrements that arise from the carryover over of gains or losses into the 2011-15 regulatory control period. That decision relates to CitiPower's revenue requirements for the forthcoming regulatory control period. It is a decision about CitiPower's future rights. It is not a retrospective decision and it does not involve retrospective application of the Rules to the ESCV's ECM. In making that decision, the AER is required by the NEL to have regard to the NEO and revenue and pricing principles.

14.3.3.5 AER reason 5: The ESCV's ECM was consistent with the NEO and revenue and pricing principles, because the requirements of the Tariff Order are similar to the Rules requirements

The AER states that the requirements of the Tariff Order under which the ESCV's ECM was made are similar to the Rules requirements.[976] The implication appears to be that the ESCV's ECM is therefore consistent with the NEO and the revenue and pricing principles.

Even if this statement is correct, the fact that the Tariff Order may impose similar requirements to the NEL and Rules does not mean that the ESCV's ECM is compliant with the NEO and revenue and pricing principles. The AER is required to consider the NEO and revenue and pricing principles and apply them to the decision that it is required to make under the Rules regarding revenue increments and decrements for 2011-15 arising from a control mechanism in 2006-10. The AER cannot reject the proposed adjustments without expressly considering the NEO and revenue and pricing principles simply because the ESCV took a particular view based on different albeit perhaps 'similar' requirements.

In any event, the AER's reasoning does not justify the rejection of CitiPower's proposed adjustments. If the requirements of the Tariff Order are similar to the Rules requirements, then that reinforces the need to consistently apply the ESCV's 'like for like' principle and allow CitiPower's proposed adjustments as an application of that principle. The ESCV's 2006-10 EDPR shows that the ESCV considered that the Tariff Order required the application of that principle,[977] and that is also the case under the Rules. Accordingly, any similarity between the Tariff Order and the Rules supports CitiPower's adjustments and is not a reason for rejecting them.

14.3.3.6 Inconsistency between the AER's rejection of these adjustments and the AER's decision to make its own adjustments

CitiPower's adjustments were proposed on the basis that they were necessary to give effect to the principle established by the ESCV and ORG Appeal Panel that adjustments are required so that actual expenditure can be compared with the original benchmarks on a 'like for like' basis. In the Draft Determination, the AER rejected these adjustments because they were not explicitly provided for in the ESCV's 2006-10 EDPR. In doing so, the AER failed to consider whether these adjustments were consistent with the established 'like for like' comparison principle and the resultant DNSP expectations.

[976] AER, Draft Determination, p576.
[977] ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), p415-438.

The AER's rejection of these adjustments cannot be reconciled with the AER's reasoning and conclusions in relation to the AER's own adjustments where the AER clearly accepts and applies the 'like for like' comparison principle.

In section 9.5.4, the AER makes adjustments to the carryover amounts under the heading 'Consistency in the measurement of actual expenditure with the ESCV benchmark allowances'. In this section, and other parts of the Draft Determination, the AER very clearly accepts the 'like for like' comparison principle and applies it to justify adjustments.

For example, the AER states: [978]

> *'The ESCV stated that for the rewards implicit in the ECM 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. The AER also notes that in its 2006 EDPR the ESCV identified a number of adjustments that it considered to be necessary to ensure a 'like for like' comparison between the benchmark allowance and actual expenditure in calculating the efficiency carryover amounts for 2006–10.'*

The AER applies this 'like for like' principle to make adjustments related to provisions, AMI readjustment, related party margins, non-recurrent expenditure, growth and changes in capitalisation policies.

The AER makes these adjustments despite explicitly acknowledging that several of these adjustments were not provided for by the ESCV in the ESCV's 2006-10 EDPR. The AER acknowledges that the adjustments made by the ESCV as a result of the 'like for like' principle were restricted to growth, capitalisation of overheads and movements in provisions. However, the AER makes its own additional adjustments based on the application of the 'like for like' principle.

In applying this principle to additional adjustments, the AER states: [979]

> *'Accordingly, the AER has reviewed the Victorian DNSPs' proposed carryover amounts and where necessary has adjusted the original ESCV benchmark allowance and the DNSPs' actual expenditure to ensure a 'like for like' comparison for the factors identified above.'*

The application of this general principle by the AER is also clear in the following statements made by the AER to justify its adjustments for provisions and related party margins: [980]

> *'Given the ESCV benchmark allowance excludes the movement in provisions the AER has also excluded the movement in provisions to ensure a 'like for like' comparison of actual expenditure and the benchmark allowance for 2006–10. The AER has also excluded any movement in provisions for the purpose of determining the base year level of operating and maintenance expenditure in chapter 7 of this decision.*
>
> ...

[978] AER, Draft Determination, p583 (footnotes omitted).
[979] AER, Draft Determination, p583.
[980] AER, Draft Determination, p587, p588 (footnotes omitted).

> *Accordingly, in assessing the carryover amounts, the Victorian DNSPs actual expenditure should be exclusive of these margins. The AER notes that from 2007 the DNSPs were required to report actual expenditure exclusive of related party margins. Accordingly, the AER has not adjusted actual expenditure for related party margins in 2007 and 2008. The AER notes that none of the Victorian DNSPs proposed removing the impact of the related party margins from actual expenditure in calculating the efficiency carryover amounts. Accordingly, to ensure that actual expenditure and the ESCV benchmark allowance is compared 'like for like', the AER has excluded the related party margins in 2006 in the carryover amounts for the Victorian DNSPs.*

The AER also applies the 'like for like' principle in its reasoning in relation to UED's carryover amounts in section 13.5.1 of the Draft Determination where the AER states:[981]

> *'In determining the carryover amounts, the AER has, where necessary, adjusted the ESCV's benchmark allowance and actual expenditure to ensure that they are compared on a like for like basis (refer to section 13.5.4). The ESCV determined United Energy's benchmark allowance exclusive of related party margins by establishing United Energy's benchmark allowance based on its actual costs prior to any related party contractual arrangements that were in place. Accordingly, the AER considers that United Energy's carryover amounts should be determined in a similar way by comparing the benchmark allowance exclusive of margins (that is, based on the actual incurred costs of the related party and not the contract charges).'*

It is therefore clear that the AER accepts that the 'like for like' principle must be applied when determining carryover amounts and that adjustments must be made to give effect to that principle.

However, the AER does not refer to that principle when assessing CitiPower's proposed adjustments in section 13.5.5 of the Draft Determination.

The 'like for like' principle must be applied to all proposed adjustments. The application of that principle clearly justifies CitiPower's proposed adjustments. It is unreasonable and incorrect for the AER to fail to apply that principle to CitiPower's proposed adjustments and to reject those adjustments because they were not explicitly provided for by the ESCV. That is particularly so when the AER has accepted the principle and applied it to justify its own adjustments, including adjustments that it acknowledges were not provided for by the ESCV.

14.4 The AER's adjustments to the 2006-10 carryover amounts

14.4.1 AER's Draft Determination

In the Draft Determination, the AER made adjustments to CitiPower's proposed 2006-10 carryover amounts in relation to the following matters:

- network growth;
- provisions;

[981] AER, Draft Determination, p561.

- licence fees;
- related party margins;
- AMI reclassification; and
- non-recurrent expenditure.982

The AER stated that these adjustments were required so that there can be a 'like-for-like' comparison between the original ESCV benchmarks in the ESCV's 2006-10 EDPR and the DNSPs' actual opex.[983]

These adjustments were not set out in CitiPower's Initial Regulatory Proposal.

14.4.2 CitiPower's response to the AER's Draft Determination

CitiPower accepts the AER's adjustments in the Draft Determination in relation to the following matters:

- AMI reclassification; and
- related party margins.

CitiPower accepts the AER's proposal that an adjustment should be made in relation to network growth. However, CitiPower does not accept the AER's estimated 2010 volume inputs for this adjustment. As explained in Chapter 7 of this Revised Regulatory Proposal, CitiPower does not accept the AER's approach to scale escalation, and CitiPower proposes that this adjustment should be calculated in accordance with CitiPower's approach to scale escalation set out in Chapter 7.

CitiPower accepts the AER's proposal that an adjustment should be made in relation to licence fees, but CitiPower does not accept the amount of the AER's proposed adjustment.

CitiPower accepts the reasoning for the AER's non-recurrent expenditure adjustment. This adjustment is based on the principles established by the ESCV in the ESCV's 2006-10 EDPR that adjustments must be made to allow a 'like for like' comparison and that any adjustments that are made to the base year opex figures must also be made to the efficiency carryover figures.

However, the AER's adjustment should not be limited to 2009 expenditure. It should apply to all uncontrollable non-recurrent expenditure that was incurred in 2006-09. The AER's adjustment only addresses expenditure in 2009 and does not address non-recurrent and uncontrollable expenditure in relation to superannuation and GSL payments in the 2006-08 period. CitiPower's proposed adjustments set out in section 14.3 of this Revised Regulatory Proposal are a more appropriate and complete mechanism to address these costs.

The AER's adjustment for non-recurrent expenditure is not necessary if the proposed adjustments in section 14.3 of this Revised Regulatory Proposal are accepted.

CitiPower does not accept the amount of the AER's adjustments in the Draft Determination in relation to provisions. The Draft Determination makes provision adjustments for

[982] AER, Draft Determination, pp596-597.
[983] AER, Draft Determination, p583.

CitiPower for the purposes of establishing base opex for 2009, the calculation of the efficiency carryover amounts arising from 2006-10 and establishing 2005-09 capex for the roll forward of the RAB. In some instances these provision adjustments are incorrect.

The provisions relating to Customer Refunds and Employee Entitlements are incorrect. The reasons these provisions have been calculated incorrectly are as follows:

- Customer Refunds (2008): The provision statement for Customer Refunds in the 2008 Regulatory Accounts is incorrect. While the overall decrease in the provision is correct, CitiPower increased its provision for Customer Refunds in relation to co-generation customers. The entry should have been shown in the provision template in the Regulatory Accounts as an '*Other Adjustment*'. However, it was included as '*Increase/Decrease in provision charged to profit*'. Accordingly, the AER included this as an adjustment to CitiPower's opex, however, there is no offsetting entry in opex.
- Employee Entitlements (2006-09):
    - Firstly, the Draft Determination uses the unaudited 2009 Regulatory Accounts to calculate the provision movement. However the final 2009 Regulatory Accounts Employee Entitlement provision statement differs from the unaudited value.
    - Secondly, the Draft Determination allocates the Employee Entitlement provision based on the labour costs in the Regulatory Accounts (which only includes labour costs for the licensee) whereas as it should be based on the labour costs of the organisation. The following table provides the appropriate labour cost split

	2006	2007	2008	2009
	Labour Costs	Labour Costs	Labour Costs	Labour Costs
Operating Expenditure	[redacted]	[redacted]	[redacted]	[redacted]
Maintenance Expenditure	[redacted]	[redacted]	[redacted]	[redacted]
Capital Expenditure	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

Table 14.2 Employee Entitlement Provision

    - Thirdly, the Draft Determination allocates the entire Employee Entitlement provision movement between capex and opex. The Employee Entitlement provision for 2008 and 2009 contains a present value adjustment for long service leave which is made in accordance with accounting standards. This adjustment is driven by assumptions in the present value calculation and therefore remains allocated to opex as per the income statement.

- The second and third issues were highlighted in CitiPower's letter to the AER of 3 February 2010 regarding 'Regulatory Accounts, Provisions and AMI Adjustment to Regulatory Accounts'.[984]

CitiPower recognises the AER will require a statement from its external auditor, Deloitte, particularly in relation to amendments to historical provision statements. Accordingly, CitiPower engaged Deloitte to review all the proposed movements in provisions proposed by CitiPower. Deloitte has confirmed the adjustments proposed by CitiPower to be correct.[985]

14.5 NPV approach

14.5.1 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower proposed that the AER adopt an NPV approach, similar to that adopted by the ESCV in the ESCV's 2006-10 EDPR. As a result of this NPV approach, CitiPower's carryover amounts for 2006-10 would be set at zero instead of a negative amount.[986]

14.5.2 AER's Draft Determination

In the Draft Determination, the AER rejected CitiPower's proposed NPV approach. The AER did not provide any reasons for this rejection. The rejection of the NPV approach in the Draft Determination is only apparent from the fact that negative amounts are included in Table 13.6 of the Draft Determination, which sets out CitiPower's 2006-10 carryover amounts.[987]

On 28 June 2010, CitiPower requested that the AER provide reasons for its rejection of the proposed NPV approach. On 29 June 2010, the AER provided the following reasons for its decision: [988]

> *'In its draft decision the AER noted that it is required to apply the ESCV's efficiency carryover mechanism (ECM). More particularly, the AER noted that under the ECM the AER must also apply the presumption that where a negative carryover arises, it will be applied in calculating the carryover amounts for the 2011-15 regulatory control period.'*

It appears from this statement that the AER considers that aspects of its reasoning in section 13.5.2 of the Draft Determination in relation to Powercor Australia's 2001-05 negative carryover also apply to CitiPower's proposed NPV approach. In section 13.5.2, the AER stated that it was required by the by the EBSS Final Decision, the ESCV's 2006-10 EDPR and the NEVA to apply the ESCV's ECM as set out in the ESCV's 2006-10 EDPR,

[984] Letter from B Cleeve, Manager Price Review, CitiPower and Powercor Australia to B Burkitt, Director Network Regulation, AER entitled 'Regulatory accounts, provisions and AMI adjustment to regulatory accounts' 3 February 2010 (Attachment 217 to this Revised Regulatory Proposal).

[985] Letter from T Imbesi, Partner, Deloitte, to J Williams, Chief Financial Officer, CHEDHA, titled 'CitiPower Regulatory Accounts: Accounting treatment of provisions', 20 July 2010 (Attachment 218 to this Revised Regulatory Proposal).

[986] Initial Regulatory Proposal, p256-259.

[987] AER, Draft Determination, p598.

[988] Email from B Burkitt, Director Network Regulation South Branch, AER to B Cleeve, Manager Price Review, CitiPower and Powercor Australia entitled 'CitiPower ECM', 29 June 2010.

including the ESCV's stated presumption that where a negative carryover amount arises for the 2006-10 period it will be applied in the 2011 period.[989]

14.5.3 CitiPower's response to the AER's Draft Determination

The AER's conclusion in the Draft Determination to reject CitiPower's NPV approach is unreasonable and inconsistent with:

- the ESCV's reasoning in the ESCV's 2006-10 EDPR, where it adopts an NPV approach for reasons that are equally applicable to the AER's decision; and
- the NEO, the revenue and pricing principles and the objectives of the ECM and the EBSS.

No reasonable decision maker would make a decision that was inconsistent with these matters, and certainly no reasonable decision maker would make such a decision without addressing this inconsistency.

As explained in section 14.3.3 of Powercor Australia's Revised Regulatory Proposal, the AER's conclusion in section 13.5.2 of the Draft Determination that it is required by the EBSS Final Decision, the ESCV's 2006-10 EDPR and the NEVA to apply the ESCV's ECM as set out in the ESCV's 2006-10 EDPR involves several errors of law. None of the ESCV's 2006-10 EDPR, the EBSS Guideline or the NEVA can authorise the AER to act in a way that is beyond its powers under the NEL and Rules, and the enforcement powers under the NEVA do not apply.

The AER is required to make a decision under clause 6.4.3(a)(6) of the Rules as to the appropriate amount of any revenue increment or decrement for CitiPower for the 2011-15 regulatory control period. In making that decision, the AER is required to have regard to the NEO and the revenue and pricing principles. The AER cannot abdicate its responsibilities under the Rules on the basis that it is giving effect to a 'presumption' by the ESCV. The AER must, at the very least, consider whether that presumption is appropriate under the current regulatory regime, having regard to the NEO, the revenue and pricing principles and the objectives of the ECM and EBSS.

As explained in the Initial Regulatory Proposal, the ESCV set out good reasons for adopting the NPV approach in the ESCV's 2006-10 EDPR and those reasons are equally applicable to the AER's decision for the Final Determination.[990]

In particular, the ESCV stated that the NPV approach is consistent with the objectives of the ECM and ensures that CitiPower's revenue requirement will not be less than is required by an efficient business. This reasoning is equally applicable to the current regulatory framework and is consistent with the requirements of the revenue and pricing principle in clause 7A(2) of the NEL. It is also consistent with the objectives of the EBSS under clause 6.5.8(c).

[989] AER, Draft Determination, pp562-570.
[990] Initial Regulatory Proposal, pp256-259.

14.6 CitiPower's Revised Regulatory Proposal

CitiPower amends its Initial Regulatory Proposal to incorporate the AER's adjustments to the 2006-10 carryover amounts in relation to related party margins and AMI reclassification.

Other than these amendments, CitiPower does not accept the AER's position in the Draft Determination.

CitiPower amends its Initial Regulatory Proposal to incorporate adjustments to the opex benchmarks and outturn opex as set out in Table 14.3 below.

CitiPower's proposed 2006-10 carryover amounts are set out in Table 14.3.

	$'000 (real 2010)									
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Opex benchmarks	40,369	41,666	41,834	42,690	43,544					
Opex benchmarks after adjustments	38,607	39,771	39,794	41,336	42,228					
Outturn opex (refer Chapter 6)	30,196	32,511	32,424	40,289						
Outturn opex after adjustments	30,196	32,511	32,424	40,289						
Incremental saving	8,411	(1,151)	109	(6,323)	-					
	Carryover gains									
2006		8,411	8,411	8,411	8,411	8,411				
2007			(1,151)	(1,151)	(1,151)	(1,151)	(1,151)			
2008				109	109	109	109	109		
2009					(6,323)	(6,323)	(6,323)	(6,323)	(6,323)	
2010						0	0	0	0	0
Carryover amount						-	-	-	-	-

Table 14.3 2006-10 efficiency carryover amounts

15. EFFICIENCY BENEFIT SHARING SCHEME

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 14 of the Draft Determination regarding the EBSS.

15.1 Summary of key points

CitiPower does not accept the AER's decision to reject CitiPower's proposal that any events that are proposed by CitiPower as nominated pass through events but are not accepted by the AER should be excluded cost categories for the purposes of the EBSS. That decision is unreasonable, incorrect and based on errors of fact.

15.2 Rules requirements

Clause 6.4.3(a)(5) of the Rules provides that one of the building blocks is *'the revenue increments or decrements (if any) for that year arising from the application of the efficiency benefit sharing scheme, the service target performance incentive scheme and the demand management incentive scheme'*.

Clause 6.4.3(b)(6) of the Rules provides that *'the revenue increments or decrements referred to in paragraph (a)(5) are those that arise as a result of the operation of an applicable efficiency benefit sharing scheme, service target performance incentive scheme or demand management incentive scheme as referred to in clauses 6.5.8, 6.6.2 and 6.6.3'*.

The AER's development and implementation of the EBSS is governed by clauses 6.5.8(a) and (c) of the Rules, which provide:

> *'(a) The* AER *must, in accordance with the* distribution consultation procedures*, develop and* publish *a scheme or schemes* (efficiency benefit sharing scheme) *that provide for a fair sharing between* Distribution Network Service Providers *and* Distribution Network Users *of:*
>
> *(1) the efficiency gains derived from the operating expenditure of* Distribution Network Service Providers *for a* regulatory control period *being less than; and*
>
> *(2) the efficiency losses derived from the operating expenditure of* Distribution Network Service Providers *for a* regulatory control period *being more than, the forecast operating expenditure accepted or substituted by the AER for that regulatory control period.'*
>
> *'(c) In developing and implementing an* efficiency benefit sharing scheme*, the* AER *must have regard to:*
>
> *(1) the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for* Distribution Network Service Providers*; and*
>
> *(2) the need to provide* Distribution Network Service Providers *with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure and, if the scheme extends to capital expenditure, capital expenditure; and*

(3) *the desirability of both rewarding* Distribution Network Service Providers *for efficiency gains and penalising* Distribution Network Service Providers *for efficiency losses; and*

(4) *any incentives that* Distribution Network Service Providers *may have to capitalise expenditure; and*

(5) *the possible effects of the scheme on incentives for the implementation of non-network alternatives.'*

The AER issued its EBSS Guideline on 26 June 2008.[991] The EBSS Guideline provides that adjustments will be made to forecast opex allowances for the purposes of calculating carryover amounts in the following circumstances:

- changes in capitalisation policies;
- differences between forecast and demand growth;
- recognised pass through events;
- a service ceasing to be a standard control service during the regulatory control period;
- adjustments for changes in responsibilities that result from compliance with a new or amended law or licence, or other statutory or regulatory requirement; and
- additional excluded cost categories that are proposed by a DNSP and accepted by the AER, which must:
    - be uncontrollable;
    - not adversely impact the operation of the EBSS;
    - be specific to the business;
    - have an identifiable reason for their exclusion; and
    - not relate to an on-going business activity.[992]

15.3 CitiPower's Initial Regulatory Proposal

In the Initial Regulatory Proposal, CitiPower proposed that the following matters should be treated as uncontrollable costs for the purposes of the EBSS:

- debt raising costs;
- superannuation costs;
- GSL payments;
- any costs related to the following events if those events are not accepted by the AER as nominated pass through events:
    - 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;

[991] AER, EBSS Guideline (Attachment 215 to this Revised Regulatory Proposal).

[992] AER, EBSS Guideline (Attachment 215 to this Revised Regulatory Proposal), pp6-7.

- 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 0Hz-3kHz, by the ARPANSA;
- costs arising from a general nominated pass through event;
- costs arising from a financial failure of a retailer event;
- costs arising from a declared RoLR event;
- fees or charges payable to the AEMO; and
- costs arising from an emissions trading scheme event.[993]

15.4 AER's Draft Determination

In the Draft Determination, the AER determined that the following costs should be treated as uncontrollable costs for the EBSS:

- debt raising costs;
- self-insurance costs
- superannuation costs for defined benefit and retirement schemes;
- the DMIA; and
- GSL payments.[994]

The AER rejected CitiPower's proposal that any costs related to events that are not accepted by the AER as nominated pass through events should be treated as uncontrollable for the purposes of the EBSS. The AER considered that it was unnecessary to treat these matters as uncontrollable costs for the purposes of the EBSS because these matters would either:

- be covered by other pass though events; or
- affect revenue and not costs and therefore would not affect the EBSS calculation.[995]

15.5 CitiPower's response to the AER's Draft Determination

15.5.1 Nominated pass through events

The AER's rejection of CitiPower's proposal that any costs related to events that are not accepted by the AER as nominated pass through events should be treated as uncontrollable for the purposes of the EBSS is unreasonable, incorrect and based on errors of fact.

In the Draft Determination, the AER stated that many of these nominated pass through events were rejected on the basis that they are already within the scope of the 'regulatory change event' or the 'service standard event' specified in Chapter 10 of the Rules.[996] On that basis, the AER considered that these events did not need to be excluded cost categories for the EBSS, because if they are covered as a 'regulatory change event' or the 'service standard event' then they will be automatically excluded from the EBSS calculations.

[993] Initial Regulatory Proposal, p248.
[994] AER, Draft Determination, p607.
[995] AER, Draft Determination, p609.
[996] AER, Draft Determination, p609.

However, the Draft Determination does not provide any certainty that the AER will treat the rejected events as regulatory change events or service standard events if and when they arise.

The AER's comments on this issue in the EBSS Chapter of the Draft Determination are inconsistent with its comments on the same issue in the pass through Chapter of the Draft Determination. In the EBSS Chapter, the AER stated that these events had been rejected as pass through events because *'they **are** events that are already within the scope of either the 'regulatory change event' or 'service standard event''* (emphasis added).[997] However, in the pass through Chapter, the AER did not find that these events 'are' regulatory change events or service standard events, but merely indicated that they **could** be within the definitions of those events.

Accordingly, there is no certainty that if these events arise, they will be excluded from the EBSS and that specific uncontrollable cost categories are not necessary.

If the AER rejects these events as uncontrollable cost categories in the Final Determination, it must confirm that the AER has determined that each of the rejected events is either a regulatory change event or a service standard event and that if and when it arises the AER will accept it as a pass through event (subject to any assessment as to whether the quantum of cost is material/immaterial). If the AER is not willing or able to provide that confirmation in the Final Determination, it cannot be assured that these events will not impact on the EBSS and the AER should include them as uncontrollable cost categories.

In the Draft Determination, the AER stated that: [998]

> *'The AER also notes that, some of the nominated pass through events proposed, such as a forced load shedding event, will impact revenues rather than costs. As such these events will not impact carryover amounts under the EBSS.'*

However, all of the events proposed by CitiPower relate to costs and not revenue and will impact the EBSS if they occur. The AER's reasoning therefore does not provide a valid reason for rejecting the uncontrollable cost categories proposed by CitiPower.

By stating that these events are likely to be pass through events, the AER appears to accept that these events are uncontrollable. Accordingly, these events will meet all of the requirements under the AER's EBSS Guideline to be an excluded cost category, i,e.:

- they are uncontrollable;
- they will not adversely impact the operation of the EBSS;
- they are specific to the business;
- CitiPower has provided an identifiable reason for their exclusion; and
- they do not relate to an on-going business activity.[999]

[997] AER, Draft Determination, p609.
[998] AER, Draft Determination, p609.
[999] AER, EBSS Guideline (Attachment 215 to this Revised Regulatory Proposal), p6.

It would therefore be inconsistent with the AER's EBSS Guideline for the AER to refuse to accept these events as uncontrollable cost categories.

Accordingly, CitiPower maintains that any nominated pass through events proposed by CitiPower that are not accepted by the AER as pass through events should be treated as uncontrollable costs and excluded from the EBSS.

15.5.2 Superannuation costs

In the Draft Determination, the AER allowed an excluded cost category for 'superannuation costs for defined benefit and retirement schemes'.[1000]

CitiPower considers that the reference to 'retirement schemes' is uncertain. CitiPower considers that the AER should clarify that this category covers both defined benefit schemes and accumulation schemes. Superannuation costs associated with accumulation schemes are uncontrollable and meet the requirements for exclusion under the EBSS Guideline.

Accordingly, CitiPower proposes that the superannuation costs exclusion should cover 'superannuation costs for defined benefit and accumulation schemes'.

15.6 CitiPower's Revised Regulatory Proposal

CitiPower proposes that the following matters should be treated as uncontrollable costs for the purposes of the EBSS:

- debt raising costs;
- self-insurance costs;
- superannuation costs for defined benefit and accumulation schemes;
- the DMIA;
- GSL payments; and
- any costs related to the following events if those events are not accepted by the AER as nominated pass through events:
    - 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 ESV;
    - 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 0Hz-3kHz, by the ARPANSA;
    - costs arising from a general nominated pass through event;
    - costs arising from a financial failure of a retailer event;
    - costs arising from a declared RoLR event;
    - fees or charges payable to the AEMO; and
    - costs arising from an emissions trading scheme event;
    - a natural disaster event;

[1000] AER, Draft Determination, p607.

- an insurance event/legal liability above insurance cap event; and
- an insurer credit risk event.

CitiPower's forecast opex for debt raising costs, self-insurance costs, superannuation costs for defined benefit and accumulation schemes, the DMIA and GSL payments is set out in Table 15.1. It is not currently possible to forecast expenditure for the events that are not accepted by the AER as nominated pass through events.

	$'000 (real 2010)					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Superannuation costs	2,044	2,074	2,148	2,277	2,478	**11,022**
DMIA	200	200	200	200	200	**1,000**
GSL payments	17	17	17	17	18	**86**
Self insurance	0	0	0	0	0	**0**
Debt raising costs	1,853	2,025	2,200	2,392	2,568	**11,038**
Total	**4,114**	**4,316**	**4,566**	**4,887**	**5,264**	**23,146**

Table 15.1 Forecast opex for uncontrollable cost categories

In response to the AER's request in the note to Table 14.1 of the Draft Determination for additional information:

- the amount of opex expended on superannuation in 2009 was $1,865,457; and
- CitiPower did not incur any expenditure on non-network alternatives in the base year.

15.7 Regulatory Information Notice response

Paragraphs 2.1 of the Further RIN requires CitiPower to identify and explain each proposed variation or departure from the Draft Determination in respect of the EBSS.

CitiPower's proposed departures from the Draft Determination in respect of the EBSS are identified and explained in section 15.5 above.

16. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 15 of the Draft Determination regarding the STPIS.

16.1 Summary of key points

CitiPower accepts the position set out by the AER in its Draft Determination in relation to the STPIS, except in respect of the S factor true up.

CitiPower does not accept the AER's decision not to include an S factor true-up term in the control mechanism and to instead address that matter in the 2016-20 Distribution Determination. CitiPower maintains that an S factor true up term should be added to the control mechanism, as set out in Chapter 4 of this Revised Regulatory Proposal.

CitiPower also does not accept the AER's proposed method for calculating the S factor true up amount.

16.2 Rules requirements

Clause 6.6.2(a) of the Rules requires that the AER publish a STPIS to provide incentives for DNSPs to maintain and improve performance.

Clause 6.6.2(b)(3) of the Rules provides that, in developing and implementing the STPIS, the AER must take into account:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;
- any regulatory obligation or requirement to which the DNSP is subject;
- the past performance of the distribution network;
- any other incentives available to the DNSP under the Rules or a relevant distribution determination;
- the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels;
- the willingness of the customer or end user to pay for improved performance in the delivery of services; and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

16.3 CitiPower's Initial Regulatory Proposal

In its Initial Regulatory Proposal, CitiPower proposed several modifications to the application of the STPIS that was proposed by the AER in the Framework and Approach Paper.

In its Initial Regulatory Proposal, CitiPower proposed that the control mechanism should include an S factor true up mechanism.[1001]

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 at the time of the AER's Final Determination, an S factor true up correction 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 S factor true up calculation are proposed to be based on actual average service performance over 2005-09 applying the current regulatory control period exclusion criteria.

16.4 AER's Draft Determination

In the Draft Determination, the AER rejected several aspects of CitiPower's Initial Regulatory Proposal, including:

- CitiPower's proposal to use 2009 expenditure as the basis for forecast GSL payments: the AER determined that the 2005-09 average should be used instead;[1002]
- CitiPower's application of a customer growth factor to its forecast GSL payments;[1003]
- CitiPower's proposal that the Final Determination should include an S factor true up mechanism.[1004]

In relation to the S factor true up, the AER noted that an S factor true up term was not included in the Framework and Approach Paper and that the Rules constrain the AER's ability to amend the form of control set out in the Framework and Approach Paper. The AER stated that the DNSPs will instead be able to recover the S factor true up amount in the 2016-20 Distribution Determination.

16.5 CitiPower's response to the AER's Draft Determination

CitiPower accepts the position set out in the Draft Determination in relation to the STPIS, except in relation to the S factor true up.

16.5.1 S factor true up

As discussed in Chapter 4 of this Revised Regulatory Proposal, CitiPower does not accept the AER's decision not to include an S factor true up term in the control mechanism.

[1001] Initial Regulatory Proposal, pp 318-320.
[1002] AER, Draft Determination, p686.
[1003] AER, Draft Determination, p687.
[1004] AER, Draft Determination, p682.

CitiPower maintains that an S factor true up term (T_t) should be added to the control mechanism. As explained in Chapter 4, CitiPower does not consider that clause 6.12.3(c) of the Rules prevents the AER from amending the control mechanism formula from that set out in the Framework and Approach Paper.

The S factor true up correction amount needs to be converted into a factor for the WAPC and side constraint formulae in accordance with the approach set out in Appendix 3.1 of this Revised Regulatory Proposal.

CitiPower also does not agree with the AER's proposed method for calculating the S factor true up correction amount. CitiPower's reasons are set out in Appendix 16.1. CitiPower also attaches its proposed S factor true up Model (Attachment 6 to this Revised Regulatory Proposal), which calculates the S factor true up amount in accordance with Appendix 16.1. This model produces the same S factor true up amount as the Draft Determination model with the same inputs, only because CitiPower's estimated performance in 2010 is set equal to its 2005-09 average performance - the equivalent of the 2011 target. Inserting any other value for 2010 performance results in the two models producing divergent results.

CitiPower agrees with the Draft Determination that the S factor correction amount to account for the difference between estimated and actual performance in 2010 should be based on the difference between the annual S factor true up amounts based on actual performance in 2010 and the annual S factor true up amounts included in the building blocks. CitiPower agrees with the Draft Determination that the annual differences in true up amounts should be present valued applying the pre-tax WACC from the PTRM.

16.5.2 Customer service parameter targets

As a result of the change in the definition of the telephone answering parameter, CitiPower's customer service parameter targets in the Draft Determination are lower than its previous targets and lower than the targets that apply to DNSPs in other States.

CitiPower notes that this change in the definition means that it is not possible to compare CitiPower's targets with previous ESCV targets or targets for DNSPs in other States. CitiPower also notes that, while the AER's new definition applied at the time of its recent determinations in other States, the customer service parameter targets in other States appear to reflect the old definition and not the new AER definition.

The additional information requested by the AER in relation to customer service targets on pages 664 and 666 of its Draft Determination is set out in Template 6.6 of the Regulatory templates provided with this Revised Regulatory Proposal in response to the Further RIN.

16.6 CitiPower's Revised Regulatory Proposal

CitiPower amends its Initial Regulatory Proposal to adopt the positions set out by the AER in the Draft Determination in relation to the STPIS, except that:

- CitiPower does not accept the AER's decision not to include an S factor true-up term in the control mechanism, and CitiPower maintains that an S factor true up term should be added to the control mechanism as set out in Chapter 4 of this Revised Regulatory Proposal; and

- CitiPower does not accept the AER's method for calculating the S factor true up amount and will provide a separate submission on that issue.
- CitiPower's proposed building blocks revenue requirements for 2011-15 in relation to the S factor true up (based on estimates for 2010) are set out in Table 16.1.

	$'000 (real 2010)				
	2011	2012	2013	2014	2015
S Factor true up	153	(2,750)	(3,186)	(210)	(6,423)

Table 16.1 S Factor true up building blocks

16.7 Regulatory Information Notice response

Paragraph 2.1 of the Further RIN requires CitiPower to identify and explain each proposed variation or departure from the Draft Determination in respect of the service target performance incentive scheme.

CitiPower does not propose any departure from the Draft Determination in respect of the STPIS.

As identified and explained in section 16.5 above, CitiPower disagrees with the AER's approach to the S factor true-up, but CitiPower does not consider that this matter relates to the '*service target performance incentive scheme*' as defined in the Rules and referred to in the Further RIN.

17. PASS THROUGH EVENTS

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 16 of the AER's Draft Determination regarding the nominated pass through events for the 2010-15 regulatory control period.

17.1 Summary of key points

In respect of the AER's decision on nominated pass through events, CitiPower submits as follows:

- The AER has fallen into error in accepting a submission by UED that the 'regulatory change event' pass through event in the Rules is confined to changes in existing regulatory obligations. Rather, a 'regulatory change event' encompasses any change in regulatory obligations during the regulatory control period, including the removal of an existing regulatory obligation, a change in an existing regulatory obligation and the imposition of a new regulatory obligation.
- In respect of pass through events which the AER rejected on the basis that they could fall within the scope of the 'regulatory change event' or 'service standard event' pass through in the Rules, the AER should either confirm that those events do fall within that scope (subject to any assessment of whether the quantum of costs is material/immaterial) or treat those events as nominated pass through events.
- Consistent with its recent distribution determinations in NSW, ACT, Queensland and South Australia, the AER should include a general pass through event as a nominated pass through event.
- The AER should include the financial failure of a retailer as a nominated pass through event, or else the AER should amend the credit support arrangements under the default UoSA to give Victorian DNSPs full credit support or provide an allowance for managing retailer failures as an opex item.
- If the AER rejects its proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs, the AER must include a nominated pass through event in its Final Determination in respect of these costs.

In respect of the materiality threshold for nominated pass through events, CitiPower submits as follows:

- The AER has acted unreasonably in setting a materiality threshold for nominated pass through events of one per cent of smoothed forecast revenue in the years of the regulatory control period that the costs are incurred. No reasonable decision maker would make a determination in respect of Victorian distribution which seeks to ensure consistency with the AER's approach to transmission regulation, but which is not consistent with its Previous Distribution Determinations.
- Any increase to the current materiality threshold in Victoria will result in a fundamental reassignment of risk between DNSP and customers, with DNSPs bearing a greater burden of the risk. If this is the AER's desired outcome then it should provide compensation to DNSPs for carrying this additional risk – for example by allowing additional expenditure through self insurance or opex, or amending the calculation of WACC to allow a premium for managing the additional risk.
- The materiality threshold for nominated pass through events (except for the financial failure of a retailer event and the transmission related costs event) should be that the

event has a 'material financial impact on the distribution business', with 'material' being interpreted according to its ordinary meaning. This is consistent with the defined pass through events under the ESCV's 2006-10 EDPR. CitiPower considers that having regard to its annual revenue profile this would result in a materiality threshold for it of $250,000 over the regulatory control period for each nominated pass through event.

- There should be no materiality threshold for the financial failure of a retailer pass through event and the transmission related costs pass through event.

17.2 Rule requirements

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 four pass through events:

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a terrorism event.

In addition to the four defined pass through events, an event nominated in a distribution determination as a pass through event is a pass through event for the purposes of the Rules.

The objective of the pass through provisions is to provide a degree of protection for DNSPs from the impact of uncontrollable changes in costs that arise during a regulatory control period.[1005] As the AER recognised in its recent Queensland and South Australian Final Determinations,[1006] the pass though mechanism recognises that an efficient revenue allowance cannot be established with complete certainty at the time of its Final Determination and that it may not be efficient to require DNSPs to manage all situations or circumstances without this revenue allowance. Accordingly, the objective of the pass through provisions is to ensure that DNSPs are compensated for uncontrollable costs during the regulatory control period. The pass through provisions allow uncontrollable changes in the costs of providing direct control services to be passed through to distribution network users during a regulatory control period.

This is consistent with the NEO and the revenue and pricing principles. The AER's determination as to whether additional pass through events should be allowed in a determination is governed by the NEO and the revenue and pricing principles. Specifically, the AER must have regard to:

- the principle in section 7A(2) that network service providers should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services; and
- the principle in section 7A(3) that network services providers should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services.

[1005] The objective of the pass through provisions in distribution is the same as the objective of the pass through provisions in transmission, AEMC's Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), pp104-5

[1006] AER, Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), p295; AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p223.

In making a decision as to what events should be included as nominated pass through events and the materiality threshold to apply to those pass through events, the AER is required to act reasonably.

The Tribunal commented on the unreasonableness ground of review in section 71C(1)(d) of the NEL in *Application by Energy Australia and Ors*[1007]. The Tribunal concluded that the ground of review was not limited to Wednesbury unreasonableness. The Tribunal gave an indication of what may constitute unreasonableness in commenting on the overlap between incorrect exercise of discretion and unreasonableness. The Tribunal said at [67] that:

> '*if the reasons for decision contain an element [of] arbitrariness, in the sense of an unexplained discretionary choice made in reaching a conclusion, then it may readily be concluded that the decision itself is unreasonable, and that the exercise of discretion miscarried or was in error'*.

Further, the Tribunal said at [68] that:

> *'[i]f a decision is not determined by reference to the applicable criteria in the NEL and the Rules, then it will readily lead to a conclusion that the exercise of any discretion in reaching the decision was incorrect, and the decision was unreasonable in all the circumstances'*.

It would be unreasonable for the AER to make a decision which is not consistent with the objective of the pass through provisions or with the NEO and revenue and pricing principles. It would also be unreasonable for the AER to make a decision which seeks to ensure consistency with transmission regulation, but which is inconsistent with its recent decisions in distribution.

17.3 CitiPower's Initial Regulatory Proposal

In Chapter 12 of its Initial Regulatory Proposal, CitiPower:

- nominated pass through events for the regulatory control period 2011-15;1008 and
- made a submission in relation to the appropriate materiality threshold for assessing pass through events.[1009]

CitiPower proposed that the materiality threshold for each nominated pass through event should be $5 million over the regulatory control period. CitiPower proposed that:

- the costs of the pass through event 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 pass through events nominated by CitiPower in its Initial Regulatory Proposal were:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework;
- changes to safety regulations introduced by the ESV;
- changes to exposure limits;
- a general nominated pass through event;

[1007] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [63]-[68].
[1008] Initial Regulatory Proposal pp276-85.
[1009] Initial Regulatory Proposal pp285-6.

- a financial failure of a retailer event;
- a declared RoLR event;
- an AEMO fees or charges event; and
- an emissions trading scheme event.

17.4 AER's Draft Determination

17.4.1 AER's Criteria for nominating pass through events

In its Draft Determination, the AER decided to move away from its approach to nominating pass through events which it had very recently applied in the Previous Distribution Determinations.[1010]

In those determinations, the AER set out eight factors to which the AER had regard in determining whether an event should be nominated as a pass through event. Of the eight factors, the AER considered that the likelihood of occurrence of an event and the DNSP's degree of control over the event were the most significant factors. The AER considered that nominated pass through events should be divided into the following two categories based primarily on the probability of the event occurring during the regulatory control period:

- specific nominated pass through events (highly likely to occur); and
- general nominated pass through events (unexpected events).

The key practical difference between the specific nominated pass through event and the general nominated pass through event was that the AER considered that a different materiality threshold should apply to specific nominated pass through events. The AER considered that specific nominated pass through events should have a materiality threshold of the administrative costs of assessing the application. The AER considered that general nominated pass through events should have a materiality threshold of one per cent of the DNSPs annual forecast revenue.

However, in its Draft Determination, the AER considered that a probability based criterion was no longer relevant to the assessment of pass through events.[1011] The AER changed its understanding of the meaning of forseeability from the NSW and ACT Final Determinations in which the AER had considered an event was foreseeable if it was more likely to occur than not in the regulatory control period. Rather, the AER considered that a pass through event should be foreseeable in that the nature of the event is foreseeable so that it can be tightly defined in advance.[1012]

The AER considered it would be more likely to treat an event as a pass through event where:[1013]

- the event is foreseen, but the cost and timing are not known;
- the event is of high magnitude; and
- the event is beyond the control of the DNSP.

[1010] AER, Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), Chapter 15; AER, South Australian Final Determination 2010-15 (Attachment 22 to this Revised Regulatory Proposal), Chapter 15; AER, NSW, Final Determination (Attachment 141 to this Revised Regulatory Proposal), Chapter 15; AER, ACT, Final Determination (Attachment 220 to this Revised Regulatory Proposal), Chapter 16.
[1011] AER, Draft Determination, p711.
[1012] AER, Draft Determination, p712 and p719.
[1013] AER, Draft Determination, p713.

The AER set out the following criteria for nominating pass through events:[1014]

- the event is not already provided for by the defined events in the Rules, through opex, through WACC or any other mechanism;
- the event is foreseeable;
- the event is uncontrollable;
- the event cannot be self-insured;
- the party who is in the best position to manage the risk is bearing the risk; and
- passing through the costs of the event would not undermine the incentive arrangements within the regulatory regime.

17.4.2 AER's rejection of certain nominated pass through events

The AER determined that it would not be appropriate to nominate as specific pass through events, events that already fall within one of the specified pass through events in Chapter 10 of the Rules. Accordingly, the AER determined that it would not nominate as specific pass through events any pass through events which could be classified as regulatory change events or service standard events.

The AER accepted the submission by UED that a 'regulatory change event' was confined to changes in existing regulatory obligations and did not encompass the removal or imposition of a new regulatory obligation or requirement.[1015] The AER considered that the service standard event could capture the pass through of material cost increases or decreases relating to the imposition of new regulatory obligations.

However, the AER noted that there may be new regulatory obligations that arise during the regulatory control period that do not meet the criteria for a service standard event.[1016] For example, a new regulatory obligation may not substantially affect the manner in which the DNSP provides direct control services. The AER said that if Victorian DNSPs consider that the defined pass though events in the Rules are problematic they should raise this issue with the AEMC.

The AER rejected the following pass through events nominated by CitiPower on the basis they **could** relate to new, changed or removed regulatory obligations that are already within the scope of the 'regulatory change event' or 'service standard event' specified in Chapter 10 of the Rules:[1017]

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework;
- changes to safety regulations introduced by the ESV;
- changes to exposure limits;
- an emissions trading scheme event; and

[1014] AER, Draft Determination, pp716-7.
[1015] AER, Draft Determination, p709.
[1016] AER, Draft Determination, p709
[1017] AER, Draft Determination, p710.

- an AEMO fees and charges event.

In so doing, the AER did not provide any certainty that it considered those events would fall within the scope of either the 'regulatory change event' or 'service standard event' specified in Chapter 10 of the Rules (subject to any assessment of whether the quantum of costs is material/immaterial).

The AER rejected the general pass through event on the basis that it did not meet the following assessment criteria:

- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime; and
- the event is foreseeable in that the nature or type of the event can be clearly identified.

The AER considered that events that would otherwise fall within a general pass through event could be captured by having a natural disaster pass through event.

The AER rejected the financial failure of a retailer event proposed by CitiPower on the basis that the costs of that event are recovered elsewhere in the regulatory regime. It considered the appropriate method to mitigate against the risk of this event is through the prudential requirements contained in clause 6.21.1 of the Rules.

17.4.3 Pass through events nominated by the AER

The AER accepted a pass through for a RoLR event.

The AER also:

- nominated a natural disaster event as a pass through event; and
- accepted the following nominated pass through events proposed by other DNSPs:
  - an insurance event/legal liability above insurance cap event;
  - an insurer credit risk event.

17.4.4 Materiality threshold

The AER determined that the materiality threshold for nominated pass through events should be one per cent of the smoothed forecast revenue in the years of the regulatory control period that the costs are incurred. The AER said that:[1018]

- its recent approach in its Previous Distribution Determinations of applying a materiality threshold to specific nominated pass through events of the administrative costs of assessing the application was erroneous;
- this threshold was consistent with the purpose of a materiality threshold to reduce the administrative burden of excessive application for pass through events, while still including events which may materially affect the business;
- this threshold had been applied to the general nominated pass through event in previous distribution determinations; and
- the materiality threshold for transmission cost pass throughs prescribed under the Rules is one per cent of the TNSP's maximum allowed revenue. Without good reason for differences, consistency between transmission and distribution regulation is desirable.

[1018] AER, Draft Determination, p175.

The AER incorrectly said that this threshold was not substantially different from the $5 million materiality threshold proposed by CitiPower and Powercor Australia.

17.5 CitiPower's response to AER's Draft Determination

CitiPower has reviewed all of the matters raised by the AER in its Draft Determination.

CitiPower disputes the AER's Draft Determination on pass throughs in respect of the following matters:

- the AER's decision not to nominate the following pass through events proposed by CitiPower:
  - a general pass through event;
  - a financial failure of a retailer event;
- the AER's failure to confirm that pass through events which it rejected on the basis that they could fall within the scope of the 'regulatory change event' or 'service standard event' pass through in the Rules do fall within the scope of those events; and
- the AER's decision to set the materiality threshold for nominated pass through events at one per cent of smoothed forecast revenue in the years of the regulatory control period that the costs are incurred.

CitiPower has revised its Initial Regulatory Proposal to:

- include specific nominated pass through events for:
  - conditions or limitations imposed by ESV on provisional acceptance of an ESMS under the Electricity Safety Act;
  - a transmission related costs event (with no materiality threshold);
  - a natural disaster event
  - an insurance event/legal liability above insurance cap event;
  - an insurer credit risk event.
- have a materiality threshold for nominated pass through events (except for the financial failure of a retailer event and transmission related costs event) that the event has a material financial impact on CitiPower, with material being interpreted according to its ordinary meaning; and
- have no materiality threshold for the financial of a retailer pass through event.

CitiPower's Regulatory Proposal in respect of pass through is otherwise that set out in its Initial Regulatory Proposal. Since CitiPower proposed a RoLR pass through event in its Initial Regulatory Proposal and the AER accepted that proposal, CitiPower's Current Regulatory Proposal includes that event.

17.5.1 Nominated Pass Through Events

17.5.1.1 AER's definition of regulatory change event

The AER erroneously accepted a submission by UED that a 'regulatory change event' pass through was confined to changes in existing regulatory obligations and did not encompass the removal or imposition of a new regulatory obligation or requirement.[1019] CitiPower submits that a 'regulatory change event' should encompass any change in regulatory obligation during the regulatory control period, including the removal of an existing regulatory obligation, a change in an existing regulatory obligation and the imposition of new regulatory obligation.

By confining a 'regulatory change event' to a change in an existing regulatory obligation, the AER has taken a very literal approach to the interpretation of 'regulatory change event'. Such an approach is contrary to the NEL which provides that in interpreting a provision of the Rules, the interpretation that will best achieve the purpose or object of the Rules is to be preferred to any other interpretation, including in particular a literal interpretation such as that adopted by the AER.[1020]

CitiPower submits that consistent with a purposive approach to interpreting the Rules, the definition of 'regulatory change event' should be interpreted in the context of the purpose of distribution pass through events.

The purpose of distribution pass through events in the Rules is consistent with the purpose of transmission pass through events – being to provide a degree of protection for DNSP's from the impact of uncontrollable costs arising during the regulatory control period.[1021] In the AEMC's Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18[1022] the AEMC noted in respect of the transmission pass through provisions in the Rules that:

> *'The objective of the cost pass-through is to provide a degree of protection for the TNSP 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 risk faced by the TNSP, which would otherwise have to be compensated for in the calculation of regulated revenues.*
>
> ....
>
> *Considering the intent of the pass through mechanism is to provide for unexpected changes outside the control of the TNSP, the Commission agrees with submissions that a regulation change event should be included in the scheme.'*

[1019] AER, Draft Determination, p709.

[1020] Section 7 of Schedule 2 to the NEL provides that 'In the interpretation of a provision of this Law, the interpretation that will best achieve the purpose or object of this Law is to be preferred to any other interpretation' and that this 'applies whether or not the purpose is expressly stated in this Law'. Section 3 of the NEL provides that Schedule 2 of the NEL applies to the Rules (see also section 41(1) of Schedule 2 to the NEL).

[1021] Standing Committee of Officials of the Ministerial Council on Energy, Changes to the National Electricity Rules to establish a national framework for the economic regulation of electricity distribution, Explanatory Material, April 2007 (Attachment 110 to this Revised Regulatory Proposal), p5 notes that '*[t]o achieve the MCE's objective of consistency where appropriate, the Exposure Draft of distribution revenue Rules largely builds on the AEMC's approach to economic regulation of electricity transmission. The Exposure Draft takes into account differences in the nature of transmission and distribution networks, based on analysis of these differences undertaken during the development of the draft Rules.'*

[1022] 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), pp104-5.

In light of the purpose of the pass through events, the definition of 'regulatory change event' should be interpreted broadly to enable a DNSP to recover costs outside of its control that arise from any positive regulatory change event and to enable customers to benefit from any negative regulatory change event. Specifically, it should be interpreted to include the removal of an existing regulatory obligation, a change in an existing regulatory obligation and the imposition of a new regulatory obligation during the regulatory control period. The AER has no basis to confine it to a change in an existing regulatory obligation.

CitiPower requests the AER to confirm in its Final Determination that it accepts that a 'regulatory change event' encompasses any change in regulatory obligation during the regulatory control period, including the removal of an existing regulatory obligation, a change in an existing regulatory obligation and the imposition of new regulatory obligation.

17.5.1.2 AER's rejection of events which could be regulatory change or service standard events

The AER rejected a number of pass through events nominated by CitiPower on the basis that they **could** relate to possible new, changed or removed regulatory obligations that are either within the scope of the 'regulatory change event' or 'service standard event'.[1023] However, the AER did not confirm that if any of these events arose during the regulatory control period, the AER would treat those events as falling within regulatory change events or service standard events (subject to any assessment as to whether the quantum of cost is material/immaterial).

As such, CitiPower seeks the AER's confirmation in the Final Determination that if the following events arise during the regulatory control period, the AER will treat these events as falling within either a regulatory change event or a service standard event (subject to any assessment as to whether the quantum of cost is material/immaterial):

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework;
- changes to safety regulations introduced by the ESV;
- changes to exposure limits;
- an emissions trading scheme event; and
- an AEMO fees and charges event.

If the AER is uncertain about whether or not each of these events would fall within the category of regulatory change event or a service standard event, the AER should treat these events as nominated pass through events. Consistent with the requirements of the NEL and the Rules, the inclusion of these events as nominated pass throughs will help to ensure that CitiPower is provided with a reasonable opportunity to recover its efficient costs, and has effective incentives in order to promote economic efficiency. The inclusion of these events as nominated pass throughs is also consistent with the AEMC's intent of introducing a pass through mechanism into the Rules[1024] and the intent of the Standing Committee of Officials of the MCE in conferring on the AER a power to nominate pass through events in distribution determinations.

[1023] AER, Draft Determination, p710.
[1024] AEMC's Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), pp104-5.

Further, these events satisfy the AER's criteria for nominated pass through events. In particular, CitiPower submits that:

- each of these events are foreseeable in that they can be identified in advance;
- each of these events are potentially of high magnitude;
- each of these events are beyond the control of DNSPs;
- the events cannot be self-insured;
- the party who is in the best position to manage the risk is bearing the risk; and
- the pass through of the costs associated with the events would not undermine the incentive arrangements within the regulatory regime.

Against this background, CitiPower submits that no reasonable decision-maker would refuse to nominate these events as pass through events, unless it was certain that the events would fall within the scope of either the 'regulatory change event' or 'service standard event' defined in Chapter 10 of the Rules (subject to any assessment as to whether the quantum of cost is material/immaterial).

17.5.1.3 The AER should not reject the general nominated pass through event

The AER rejected the general pass through event as a nominated pass through event.

The AER observed that it had revised its view of 'forseeability' since the Previous Distribution Determinations. It **now** considered that 'forseeability' should be viewed in terms of whether the event is capable of being tightly defined in advance rather than the probability of the event occurring.

The AER referred to its pass through guideline for the treatment of pass throughs in transmission.[1025] It noted that the guideline provided that all pass through events should be tightly defined in advance to minimise regulatory discretion during the regulatory control period.[1026] It noted that this aim is achieved through the removal of the general pass through event and its replacement with a natural disaster event.

CitiPower submits that the AER's guideline for the treatment of pass throughs in transmission is irrelevant to a consideration of what events should be nominated pass through events in the context of distribution. While distribution and transmission pass through events have the same objective, it is clear that the Rules recognise that there is a distinction in how they are defined. Transmission pass through events are all defined in the Rules, whereas the AER has an ability to define additional distribution pass through events.

The Explanatory Material in respect of the Rules as they apply to distribution,[1027] recognises the difficulties with specifying pass through events for distribution. It notes that while there has been a consistent approach by jurisdictional regulators to defining pass through events for transmission, which allows for codification in the Rules, there has not been such an approach for distribution. The fact that there has not been a consistent approach by jurisdictional regulators to defining pass through events for distribution shows that it is

[1025] AER, Statement of principles for the regulation of electricity transmission revenues, Position paper, Pass-throughs and revenue-cap re-openers, December 2005.

[1026] AER, Draft Determination, p719.

[1027] Standing Committee of Officials of the Ministerial Council on Energy, Changes to the National Electricity Rules to establish a national framework for the economic regulation of electricity distribution, Explanatory Material, April 2007 (Attachment 110 to this Revised Regulatory Proposal), p53.

difficult to anticipate with any certainty the kinds of pass through events which may arise in distribution over the regulatory control period. Given this uncertainty it is important to have a general pass through event category.

A general pass through event is also consistent with the objective of the pass through provisions in the Rules that DNSPs should not be left out of pocket for uncontrollable events which arise during the regulatory control period. Unlike TNSPs, there is no provision in the Rules which enables DNSPs to reopen revenue caps and pass through to consumers the costs of an event which arises during the regulatory control period which is beyond the reasonable control of the provider.

The AER rejected the general pass through event on the basis that it did not meet the following assessment criteria:

- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime; and
- the event is foreseeable in that the nature or type of the event can be clearly identified.

It is unclear to CitiPower how having a general pass through event would undermine the incentive arrangements within the regulatory regime. Rather, it is consistent with those incentive arrangements that DNSPs should have some protection against uncontrollable events which arise during the regulatory control period.

In addition it is consistent with the objective of the pass through provisions that DNSPs should be permitted to pass through uncontrollable costs, even where events arise during the regulatory control period that cannot be clearly identified at the time of the AER's Determination. The AER's establishment of a criterion for a nominated event that it be foreseeable in that the nature or type of the event can be clearly identified hinders the achievement of the NEO and the revenue and pricing principles, and is inconsistent with the purpose of conferring on the AER a power to nominate pass through events in distribution determinations.

The AER's rejection of the general pass through event is inconsistent with its inclusion of this event in each of its Previous Distribution Determinations. There is no basis for the AER to permit a general pass through event for distributors in other jurisdictions, but to reject it for Victorian distributors.

The AER considered that events that would otherwise fall within a general pass through event could be captured by having a natural disaster event. However, having a natural disaster event does not provide protection to DNSPs for all kinds of events which would fall within a general pass through event.

CitiPower submits that no reasonable decision-maker would refuse to nominate a pass through for a general pass through event.

17.5.1.4 The AER should not reject the financial failure of a retailer event

The AER rejected the financial failure of a retailer event on the basis that the appropriate method to mitigate against the risk of a retailer failure event is through the prudential requirements contained in clause 6.21.1 of the Rules.

However, it not possible for Victorian DNSPs to do this because they are constrained by their distribution licences to implement in the default UoSA[1028] provisions which reflect the

[1028] Attachment 226 to this Revised Regulatory Proposal.

credit support arrangements in the EESCV Credit Decision. These credit support arrangements do not fully compensate DNSPs for retailer failure.

As set out below in the discussion on materiality threshold, these credit support arrangements were put in place on the basis that Victorian DNSPs had a pass through event for a financial failure of a retailer event.

If the AER wants to reject the financial failure of a retailer as a pass through event, the AER will have to amend the credit support arrangements under the default UoSA to give distributors full credit support.[1029] If not, it should grant the pass through event.

The specification of a retailer failure event as a nominated pass through event is consistent with the requirements of the NEL and Rules and should be accepted by the AER. The inclusion of this event will help to ensure that CitiPower is provided with a reasonable opportunity to recover its efficient costs, and has effective incentives in order to promote economic efficiency.

The AER has indicated that it wishes to maintain incentives put in place by the ESCV to ensure a smooth transition to the new regulatory framework.[1030] CitiPower observes that a financial failure of a retailer event was a defined event in the ESCV's 2006-10 EDPR.[1031] It is therefore consistent with the AER's approach to maintaining incentives put in place by the ESCV that there be a pass through for a financial failure of a retailer event.

If the AER determines to reject the retailer failure event as a nominated pass through event, this will result in a fundamental reassignment of risk from customers to DNSPs. As a result, DNSPs will carry a greater portion of risk in managing cost variations. The AER has not provided any compensation for DNSPs for carrying this additional risk. It has not allowed any additional expenditure through self insurance or opex because both of these are based on revealed 2009 costs. Nor has the AER amended its calculation of WACC to allow a premium for managing the additional risk. As set out above, in referring to the objective of a pass through mechanism in the Rules for transmission the AEMC observed that if the risk faced by the TNSPs of unexpected changes in costs outside of their control was not addressed by a cost pass through provision, that risk would have to be compensated for in the calculation of regulated revenues.[1032] The AEMC's observation is equally applicable to the increased risks Victorian DNSPs will face if the AER does not nominate the financial failure of a retailer event as a pass through.

The financial failure of a retailer event satisfies all of the AER's criteria for nominating pass though events. Specifically, CitiPower observes that:

- the event is not already defined in the Rules or compensated for elsewhere;
- the event is foreseeable in that the nature of the event can be clearly identified;
- the event is uncontrollable;
- the event cannot be self-insured;

[1029] Under clause 4.1 of the distribution licence agreement, the AER has the power to direct a distributor to submit a proposed default UoSA to it.
[1030] AER, Draft Determination, p722.
[1031] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p 61.
[1032] AEMC's Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), p104.

- the party who is in the best position to manage the risk is bearing the risk; and
- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

As set out in Chapter 12 of its Initial Regulatory Proposal, a financial failure of a retailer pass through event should cover the difference between the amount CitiPower would have been entitled to receive had the retailer not failed, less any amount that is recovered pursuant to those protections within its use of system agreement. [1033]

CitiPower's proposed definition is:

> **A financial failure of a retailer event** means the occurrence of an event whereby the 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.

17.5.1.5 Electricity Safety Management Scheme

In its Initial Regulatory Proposal, CitiPower proposed a step change in respect of the amendment to the Electricity Safety Act which requires all Victorian DNSPs to operate under an ESMS which has been approved by ESV as complying with the Electricity Safety Act and the Electricity Safety (Management) Regulations.[1034] The AER rejected CitiPower's proposed step change.[1035]

The amendment to the Electricity Safety Act came into effect on 1 January 2010 and the amendment to the Electricity Safety (Management) Regulations came into effect on 13 December 2009.

Under the Electricity Safety Act , CitiPower is required to submit an ESMS to ESV for its supply networks (section 99). Section 102 of the Electricity Safety Act provides that ESV must accept an ESMS if it is satisfied that the ESMS is appropriate for the supply network to which it applies and complies with the Electricity Safety Act and the Electricity Safety (Management) Regulations. Section 103 of the Electricity Safety Act provides that ESV may provisionally accept an ESMS if it is satisfied that it will provide for the safe operation of the supply network. In respect of a provisional acceptance of an ESMS, section 103(3) gives ESV the power to impose any limitations or conditions that will apply in respect of the design, construction, operation, maintenance or decommissioning of the supply network while the provisional acceptance is in force.

Conditions or limitations which ESV imposes on a provisional acceptance of an ESMS have the potential to materially increase CitiPower's costs of providing direct control services. Accordingly, CitiPower proposes that there be a nominated pass through event for conditions or limitations imposed by ESV on its provisional acceptance of an ESMS under the Electricity Safety Act.

The inclusion of this pass through event will help to ensure that CitiPower is provided with a reasonable opportunity to recover its efficient costs, and has effective incentives in order to promote economic efficiency. The inclusion of this event as a nominated pass through is consistent with the NEL and the Rules. It is also consistent with AEMC's intent of introducing a pass through mechanism into the Rules[1036] and the intent of the Standing

[1033] Initial Regulatory Proposal p282.
[1034] Initial Regulatory Proposal, pp176-77.
[1035] AER, Draft Determination, Appendix L, p159.
[1036] AEMC's Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), pp104-5.

Committee of Officials of the MCE in conferring on the AER a power to nominate pass through events in distribution determinations.

Further, this event satisfies the AER's criteria for nominated pass through events. In particular, CitiPower submits that:

- it is foreseeable in that it can be identified in advance;
- it is potentially of high magnitude;
- it is beyond the control of DNSPs;
- the event cannot be self-insured;
- the party who is in the best position to manage the risk is bearing the risk; and
- the pass through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

CitiPower submits that no reasonable decision-maker would refuse to nominate a pass through for conditions or limitations imposed by ESV on its provisional acceptance of an ESMS under the Electricity Safety Act.

CitiPower proposes that this pass through event would be defined as follows:

> **An electricity safety management scheme event** means an event which relates to the imposition by ESV of conditions or limitations in respect of the design, construction, operation, maintenance or decommissioning of the supply network on its provisional acceptance of an electricity safety management scheme under section 103 of the Electricity Safety Act.

17.5.1.6 Transmission related costs event

In Chapter 3 of this Revised Regulatory Proposal, CitiPower proposed that the AER should include a new term in each of the WAPC and side constraint formulas to address Transmission-related Costs.

In preparing this Revised Regulatory Proposal, CitiPower has proceeded on the basis that the AER will accept its proposal to include new terms in the WAPC and side constraint formula to address Transmission-related Costs.

However, as set out in Chapter 3, CitiPower submits that if the AER rejects its proposed WAPC or side constraint terms (or both of them) regarding transmission related costs, the AER must include a nominated pass through event in its Final Determination in respect of these costs. The 'transmission related costs event' should cover the difference between forecast and actual expenditure in respect of PFIT payments, transmission connection charges, inter-DNSP charges and Avoided TuOS and Avoided DuOS payments.

17.5.2 Materiality threshold

In the following section, CitiPower explains why:

- the AER's imposition of a materiality threshold of one per cent of the smoothed forecast revenue is erroneous;
- the materiality threshold for nominated pass through events (except for the financial failure of a retailer event and transmission related costs event) should be that the event has a 'material financial impact on the distribution business', with 'material' being interpreted according to its ordinary meaning; and

- the financial failure of a retailer event and the transmission related costs event should have no materiality threshold.

17.5.2.1 AER's imposition of its materiality threshold erroneous

The AER determined that the materiality threshold for nominated pass through events should be one per cent of the smoothed forecast revenue in the years of the regulatory control period that the costs are incurred.

CitiPower asserts that the AER has acted unreasonably in setting the materiality threshold at one per cent of smoothed forecast revenue. This is because:

- the imposition of this threshold is inconsistent with the AER's reasoning in rejecting the materiality threshold applied to specific nominated pass through events in recent distribution decisions of seeking to align the threshold with the ordinary meaning of 'materially';
- in setting the threshold, the AER had regard to ensuring consistency with transmission. No reasonable decision maker would make a determination in respect of Victorian distribution which seeks to ensure consistency with the AER's approach to transmission regulation, but which is not consistent with its Previous Distribution Determinations;
- the AER justified the threshold as the threshold applied to general nominated pass through events in Previous Distribution Determinations, however, here the AER is seeking to apply the threshold to specific nominated pass through events. It did not apply this threshold to specific nominated pass through events in Previous Distribution Determinations, nor did jurisdictional electricity regulators in other States in their previous price determinations;
- the threshold which the AER sought to apply in its Draft Determination is onerous and leads to perverse outcomes. The imposition of the threshold results in a fundamental reassignment of risk between DNSPs and the customers, which increased the risk the DNSPs would have to be compensated for through regulated revenues.

The AER also incorrectly observed that this threshold was not substantially different from the $5 million threshold proposed by CitiPower and Powercor Australia.

Inconsistent reasoning

The AER rejected the materiality threshold it had applied to specific nominated events in its Previous Distribution Determinations on the basis that an event which only meets the administrative costs materiality threshold may not ultimately qualify as a 'positive change event' under the Rules (which is defined as a pass through event that materially increases the costs of providing direct control services).[1037] Accordingly, it considered it appropriate to align the materiality threshold for additional pass through events with events which meet the ordinary meaning of the word 'materially'. The AER recognised that 'materially' is not defined in the Rules and therefore must be interpreted in accordance with its plain and ordinary meaning. CitiPower observes that 'materially' is in fact defined in the Rules to have its ordinary meaning outside of the application of clause 6A.7.3 in respect of transmission pass throughs.

[1037] AER, Draft Determination, p714.

The AER then proceeded to impose a materiality threshold of one per cent of revenue. Imposing this threshold fails to align the threshold with the definition of 'positive change event' and is inconsistent with the AER's statement that it 'will align the materiality threshold contained for additional pass through events that meets the ordinary meaning of the word 'materially'.[1038] CitiPower observes that 'material' is defined in the Shorter Oxford Dictionary[1039], relevantly, as 'serious, important; of consequence'.

Accordingly, if the materiality threshold were to be aligned with the definition of 'positive change event', the materiality threshold would be that the event is material within the ordinary meaning of 'material' and each event when it arose would be assessed against that threshold. This is consistent with the ESCV's 2006-10 EDPR.[1040] Further, such a threshold would achieve the AER's stated objective of a materiality threshold to '*reduce the administrative burden of excessive applications for pass through events, while still including events which may materially affect the business'*.[1041] This objective would not be achieved if the materiality threshold were set at one per cent of forecast revenue because most events which materially affect the business would fail to satisfy this high threshold.

Desire to maintain consistency with transmission erroneous

The main reason for the AER deciding on a threshold of one per cent of smoothed forecast revenue appears to be the AER's desire to maintain consistency between its determination in respect of Victorian distribution and its approach to transmission regulation.[1042] Under the Rules, the materiality threshold for transmission cost pass throughs is prescribed as one per cent of the TNSP's maximum allowed revenue. The AER stated that '*without a good reason for the differences, consistency between transmission and distribution regulation is desirable'*.

CitiPower asserts that there is a good reason for a difference between the materiality threshold for transmission and that for distribution. Further, no reasonable decision maker would make a decision which seeks to ensure consistency with transmission, but which is not consistent with its Previous Distribution Determinations.

It is clear that the Rules make a distinction between the materiality threshold for transmission and distribution pass throughs in the definition of 'materially'. Chapter 10 of the Rules defines "materially" as:

- in the context of transmission pass throughs in clause 6A.7.3, one per cent of the maximum allowed revenue for the transmission network service provider for the regulatory year; and
- in other contexts, the word has its ordinary meaning.

Accordingly, the Rules prescribe a different meaning of 'materially' to transmission pass throughs, than to distribution pass throughs. If it was intended that distribution pass throughs were to have the same materiality threshold as distribution pass throughs the definition of 'materially' in Chapter 10 of the Rules would reflect this.

[1038] AER, Draft Determination, p714.
[1039] (5th ed 2002)
[1040] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p 61.
[1041] AER, Draft Determination, p715.
[1042] AER, Draft Determination, p715.

Statements made by the Standing Committee of Officials of the MCE in deciding not to establish a revenue cap reopener for pass through events occurring in distribution also recognise that what is a material cost impact for distribution will differ from what is material for transmission. Clause 6A.7.1 enables TNSPs to reopen revenue caps and pass through costs to customers where the capital costs of an event is beyond the reasonable control of the provider. This is subject to a materiality threshold that the total capex required during the regulatory control period to rectify the consequences of the event exceeds 5 per cent of the RAB for the TNSP for the first year of the regulatory control period. The Rules for distribution do not include such a revenue cap reopener provision. The explanatory material for Chapter 6 of the Rules noted that this provision was not necessary for DNSPs because high magnitude events that would likely trigger the reopener provision for TNSPs would be unlikely to occur in a distribution network.[1043] This shows that what is material in distribution is likely to be lower than in transmission. Accordingly, the materiality threshold in distribution should be lower than in transmission.

One per cent of revenue threshold not previously applied to specific nominated pass throughs

Another reason the AER gives for applying the one per cent materiality threshold was that this threshold had been applied to the general nominated pass through event in previous distribution determinations. However, in the Draft Determination, the AER was seeking to apply the one per cent of revenue threshold to specific nominated pass through events and, far from being consistent with previous distribution determinations, the AER's application of the one per cent of revenue threshold to specific nominated pass through events is inconsistent with the Previous Distribution Determinations.

The one per cent threshold was not the threshold the AER very recently applied to specific nominated pass through events in its Previous Distribution Determinations. In those determinations, the AER imposed a materiality threshold of the administrative costs of assessing the pass through application for specific nominated pass through events.

Nor is it the materiality threshold the ESCV applied in its 2006-10 EDPR. Rather, the threshold in the ESCV's 2006-10 EDPR was that the event 'has a material financial impact on the distribution business'.[1044] Further, while a one per cent of revenue threshold has been applied by the Queensland Competition Authority in Queensland and the Independent Pricing and Regulatory Tribunal in NSW, that was to a general pass through event and not to specific nominated pass through events.[1045]

[1043] Standing Committee of Officials of the Ministerial Council on Energy, Changes to the National Electricity Rules to establish a national framework for the economic regulation of electricity distribution, Explanatory Material, April 2007 (Attachment 110 to this Revised Regulatory Proposal), p53.
[1044] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p 61.
[1045] In its NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination (Attachment 221 to this Revised Regulatory Proposal), p28, p44, the Independent Pricing and Regulatory Tribunal applied a materiality threshold to general pass through events of the average annual change in costs in respect of the event exceeds one per cent of the average annual smoothed revenue requirement for the DNSP. In its Final Determination on the Regulation of Electricity Distribution 2005-10 (Attachment 222 to this Revised Regulatory Proposal), the Queensland Competition Authority, p50 applied a materiality threshold to general pass through events of one per cent of actual annual regulated revenue per event, based on the regulated revenue in the year of the event.

AER's threshold onerous and leads to perverse outcomes

A materiality threshold of one per cent of smoothed forecast revenue is onerous and leads to perverse outcomes for the reasons explained below.

The AER's materiality threshold results in a fundamental reassignment of risk from customers to the DNSPs. Under the current situation in Victoria under the ESCV's 2006-10 EDPR, the 'materiality threshold' for the pass through events specified in the ESCV's 2006-10 EDPR is contained in the definition of those pass through events which provides that the event must have a 'material financial impact on the distribution business'. [1046] 'Material' is not defined in the ESCV's 2006-10 EDPR and, accordingly, it takes its ordinary meaning. Again, CitiPower observes that 'material' is defined in the Shorter Oxford Dictionary[1047], relevantly, as 'serious, important; of consequence'. This is a lower threshold than the AER's proposed threshold of one per cent of smoothed forecast revenue.

The Victorian DNSPs must be compensated for any increase in the risks allocated to them under the AER's determination as compared to the ESCV's 2006-10 EDPR through regulated revenues. The AEMC recognised this, at the time of making Chapter 6A of the Rules, in commenting on the inclusion of a pass through mechanism in that Chapter. More specifically, the AEMC recognised that, in the absence of such a pass through mechanism, the risks faced by a TNSP would be higher and the TNSP would have to be compensated for this through regulated revenues, as follows:[1048]

> *'Such a mechanism lowers the risk faced by the TNSP, **which would otherwise have to be compensated for in the calculation of regulated revenues**'* [emphasis added].

The AEMC's observation above is equally applicable to the increased risks a Victorian DNSP will face if the AER's Final Determination imposes a higher materiality threshold for pass through events than is currently imposed by the ESCV's 2006-10 EDPR.

The AER has not provided any compensation to the DNSPs for carrying this additional risk. It has not allowed any additional expenditure through self insurance or opex because both of these are based on revealed 2009 costs. Nor has the AER amended its calculation of WACC to allow a premium for managing the additional risk. Further, the AER has made no adjustments to the EBSS scheme and as a result the impact of the materiality threshold is compounded by five times.

If the AER determines to apply the one per cent of smoothed forecast revenue threshold, there will also be an implicit change in the way efficiencies will be shared between customers and DNSPs. DNSPs will carry the risk of incurring up to an additional one per cent of their revenues in costs each year which will result in penalties under the EBSS. Previously these costs would have been treated as pass throughs and therefore would not have been included in the EBSS calculation. This represents a fundamental shift in the

[1046] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p 61.
[1047] (5th ed 2002).
[1048] AEMC's Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18, 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), p104.

sharing ratio that underpins the EBSS because the ability for DNSPs to make efficiency gains has become proportionally harder.

There is an asymmetry in the relative frequency of positive versus negative pass through events, with most events that may be categorised as pass through events being positive (ie resulting in DNSPs incurring increased costs). This is because, over time, the regulation of distribution becomes, on balance, increasingly onerous. This asymmetry results in systemic under-recovery by the DNSPs of uncontrollable costs. The application of the AER's one per cent of revenue threshold will compound this under-recovery of uncontrollable costs over time. The AER does not explain how the DNSP is to recover the resultant shortfall. Unless the AER systematically over-forecasts capex and opex, then the DNSP cannot be expected to over-recover as a result of those forecasts and it is unclear how the DNSP is to recover those otherwise unrecovered uncontrollable costs. In the longer term this may undermine the viability of the DNSP and its capacity to invest.

If the AER adopts a materiality threshold of one per cent of annual forecast revenue for specific nominated events, this would have the result that it is likely that CitiPower would rarely be able to recover its costs of pass through events, even where those costs are significant. Unless some other form of compensation in the building blocks is provided to cover this expected shortfall, the AER's approach is contrary to the NEO, in particular the objective of promoting efficient investment in electricity services, and the revenue and pricing principles in section 7A of the NEL, in particular that network service providers should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services and be provided with effectives incentives for efficient investment in their distribution systems.

In its South Australian Final Determination, the AER stated that its rationale for applying a threshold by reference to costs and revenues in the relevant regulatory year was because of the capacity of DNSPs to better manage costs that occur over a number of years.[1049] This approach is not justified on the basis of the AER's stated rationale, in that the timing of costs does not impact on a DNSP's ability to manage those costs, and may result in perverse outcomes. For example, costs may or may not meet the threshold based on their timing relative to the beginning/end of the regulatory year. If the costs are incurred over December/January, for example, there is less likelihood they will meet the threshold than if incurred over June/July. There is no rationale for such an outcome. The fact that the costs are incurred over December/January rather than June/July does not mean the DNSP is more capable of managing those costs. The application of the AER's materiality threshold to Powercor Australia and CitiPower based on the revenue forecast in the AER's Draft Determination is shown in the following table:

Year	2011	2012	2013	2014	2015
Materiality threshold	$2.1M	$2.2M	$2.2M	$2.3M	$2.5M

Table 17.1 Application of Materiality Threshold

[1049] AER, South Australian Final Determination, (Attachment 22 to this Revised Regulatory Proposal), p232.

AER's threshold inconsistent with $5 million materiality threshold previously proposed by CitiPower and Powercor Australia

The AER said that the one per cent of revenue threshold was not substantially different from the $5 million materiality threshold proposed by CitiPower.[1050] However, in making this assessment the AER has misunderstood that CitiPower proposed the materiality threshold should be $5 million over the regulatory control period and the costs of the pass through event should be assessed over the five year regulatory control period, rather than in a single year of the regulatory control period. Accordingly, the materiality threshold suggested by CitiPower is significantly lower than the threshold of one per cent of smoothed revenue which the AER seeks to impose.

17.5.2.2 ESCV's materiality threshold should apply

CitiPower has revised its view of the materiality threshold given the AER's Draft Determination. In revising its view of the materiality threshold, CitiPower has had regard to the AER's observations that the meaning of 'materially' in the definition of 'positive change event' and 'negative change event' takes its ordinary meaning and that it is desirable to align the materiality threshold for additional pass through events with the ordinary meaning of the word 'materially'. In addition, CitiPower has had regard to the AER's stated purpose of a materiality threshold being to reduce the administrative burden of excessive applications for pass through events, while still including events which may materially affect the business.

CitiPower has also had regard to the AER's exclusion of any specific compensation to DNSPs for carrying additional risk and the AER's refusal to address the perverse implications for the EBSS.

CitiPower submits that the materiality threshold for nominated pass through events (except for the retailer failure and transmission related costs events) should be that the event is 'material' within its ordinary meaning. This is consistent with the definition of a 'positive change event' and 'negative change event'. It is also consistent with the definition of 'materially' in Chapter 10 of the Rules which provides that outside of clause 6A.7.3, 'materially' has its ordinary meaning.

Significantly, it is consistent with the defined pass through events under the ESCV's 2006-10 EDPR which must have a 'material financial impact on the distribution business' in order to qualify as pass through events.[1051] As set out above, CitiPower submits that any change to the current materiality threshold will result in a fundamental reassignment of risk between DNSPs and customers.

Unless the AER will compensate DNSPs for the additional risks they would bear as a result of an increase in the materiality threshold for pass through events, the AER should maintain the materiality threshold used by the ESCV in its 2006-10 EDPR.

CitiPower considers that having regard to its annual revenue profile this would result in a materiality threshold for it of $250,000 over the regulatory control period for each nominated pass through event.

[1050] AER, Draft Determination, p715.
[1051] ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p 61.

17.5.2.3 No materiality threshold to apply to retailer failure events

In response to the AER's decision in its Draft Determination not to allow a retailer failure event as a specific nominated pass through event, CitiPower has given further consideration to the rationale for allowing a retailer failure event.

This further consideration has been undertaken against the background of an event that arose since its Initial Regulatory Proposal, namely the failure of another retailer Jackgreen in December 2009.

Due to CitiPower's further consideration of the rationale for a retailer failure event, CitiPower has revised its view of the materiality threshold for retailer failure events. CitiPower considers that there should be no materiality threshold for retailer failure pass through events.

It is not appropriate for a materiality threshold to apply to a distributor for a retailer default because:

- the existing credit support arrangements for Victorian DNSPs for failure of a retailer do not recover the full amount of the outstanding debt to the DNSP and this shortfall in cost recovery can be significant;
- the residual costs to DNSP's of a retailer failure should be borne by consumers and not DNSPs because:
    - the costs of retail contestability should be borne by the beneficiaries of that contestability, that is, by consumers; and
    - consumers are best placed to bear the costs of the financial failure of a retailer because these costs can be spread across a diversified consumer base; and
- accordingly, the ESCV consultant that designed the current credit support arrangements, ACG, recommended those arrangements on the basis of its understanding that the DNSPs would be able to recover any shortfall in the recovery of its costs on the failure of a retailer through a pass through mechanism that was not subject to any materiality threshold.

If the AER decides to apply a materiality threshold to retailer failure events, CitiPower seeks a greater allowance for bad debts to enable it to recover the costs of retailer failures. Such costs would have to be allowed by the AER as they would meet the opex criteria, that is, they are efficient costs that would be incurred by a prudent operator in achieving the opex objectives and thus, must be allowed by the AER. CitiPower has not proposed additional costs associated with bad debts on the assumption that it would be able to pass through any retailer failure costs to customers. In removing this possibility, the AER has altered the allocation of the risk of a retailer failure such that it is now CitiPower that carries the risk of retailer failure. CitiPower is not funded to do this through its WACC or its expenditure allowances. If the AER wants to shift the risk of retailer failure from customers to CitiPower, it must provide compensation to CitiPower for carrying this risk.

The credit support arrangements for retailer failure in Victoria are insufficient to compensate Victorian DNSPs for retailer failures. The current credit support arrangements between retailers and DNSPs that are to be reflected in the default UoSA were determined by the ESCV in the ESCV Credit Decision. In the ESCV Credit Decision, the ESCV determined that a retailer will be required to provide credit support to a distributor when the amount of the retailer's average billed and unbilled distribution service charges liability exceeds its credit allowance.

The amount of credit support provided by the retailer equals the amount by which the retailer's average billed and unbilled distribution service charges over a three month period exceeds the retailer's credit allowance. The retailer's credit allowance is calculated as the percentage of the relevant distributor's maximum credit allowance corresponding to its credit rating. The distributor's maximum credit allowance is equal to 33.33 per cent of the distributor's annual distribution service charges revenue for the most recent year reported to the ESCV.

In the ESCV Credit Decision, the ESCV adopted the model developed by ACG who conducted a review of credit support arrangements on the ESCV's behalf. In determining what model to recommend, ACG placed emphasis on the fact that the ESCV's 2006-10 EDPR had established a mechanism for distributors to pass through to customers 'the net financial consequences associated with retailer default'.[1052] The pass through mechanism which ACG understood applied was one that enabled distributors to recover losses as a result of the financial failure of a retailer from the end customer, without any materiality threshold. ACG noted that the pass through arrangements isolate the distributor from the long run financial consequences of a retailer failing and transfer the residual credit risk from the distributor to the end customer.[1053]

ACG considered that the existence of this pass through mechanism provided more flexibility in deciding on the credit risk framework for Victoria because end customers were able to bear more risk than individual distributors.[1054] ACG noted that end customers do not necessarily require the same degree of protection that an individual distributor accepting full credit risk would require. This is because:

- the customer base is diversified. ACG noted that, shared across all electricity customers in Victoria, the unrecoverable financial losses of an individual retailer liquidating will be diluted compared to the impact on a single distributor being forced to absorb the loss; and
- end customers, as the direct beneficiaries of competition between retailers have an interest in forgoing the protection of absolute credit cover, instead of accepting the risk that they might be asked to pay the cost of a retailer defaulting in the future. AGC noted that the more security a retailer is required to post, the higher its cost base will be which will ultimately be passed onto consumers by way of higher electricity prices.

Accordingly, ACG recommended a regime which sought to promote greater retail competitiveness through reducing barriers to entry to retailers in the knowledge that the distributor could recover the difference between credit support and actual loss directly through a pass through mechanism.

As a result of the ESCV Credit Decision, in practice CitiPower holds almost no credit support. Further, 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.

The ESCV Credit Decision extends a credit allowance to retailers with very low credit ratings. Retailers with credit ratings below BBB- are given a credit allowance. This means that retailers can develop such a sizeable debt before a distributor can ask for credit support,

[1052] The Allen Consulting Group, Retailer DuOS Credit Support Arrangements Implementation Issues in Victoria, Report to Essential Services Commission, June 2006 (Attachment 224 to this Revised Regulatory Proposal), p10. See also p2, 11, 37.

[1053] The Allen Consulting Group, Retailer DuOS Credit Support Arrangements Implementation Issues in Victoria, Report to Essential Services Commission, June 2006 (Attachment 224 to this Revised Regulatory Proposal), p10.

[1054] The Allen Consulting Group, Retailer DuOS Credit Support Arrangements Implementation Issues in Victoria, Report to Essential Services Commission, June 2006 (Attachment 224 to this Revised Regulatory Proposal), p11.

that it is probable those retailers would be under financial distress by the time the distributor asks for support and, as a consequence, would be unable to provide that requested support. Further, retailers with a low credit rating are effectively not required to seek insurance cover or even provide a bank guarantee.

For example, a retailer where a bankruptcy petition has been filed could have a credit rating of C and still have access to a credit allowance of 0.033 per cent of the annual distribution service charges revenue.[1055] If the distributor's annual distribution service charges revenue is $400m, this equates to an unsecured credit allowance of $133,000 to a business that is an extreme credit risk.[1056]

In addition, in the event of a retailer default a distributor is not able to simply cease supply. The distribution use of service debt will continue to accumulate until the retailer rectifies the default or customers are transferred to another retailer under commercial arrangements or by use of the RoLR mechanism. The default UoSA stipulates the procedures required to terminate the agreement in the event of default. This takes a minimum of 42 days after the bill is issued. Further time, at least 28 days, is required for the ESCV to revoke the retail licence and trigger a RoLR event, unless the retailer is also in default of their wholesale obligations and loses its right to acquire electricity from the wholesale market. In addition to the 70 days described above, there is also a substantial unbilled distribution service charges at the time of billing, typically 14 days for monthly billed customers and 46 days for quarterly billed customers. Therefore, depending on the ratio of monthly and quarterly customers, the value at risk would be in the range of 84 to 116 days of distribution use of service charges.

The application of a materiality threshold by the ESCV in the ESCV's EDPR 2006-10 and by the AER in the Queensland and South Australian Distribution Determinations provides no precedent for the application of a materiality threshold to a failure of a retailer event in the AER's Final Determination. This is because the credit support arrangements in place in Victoria at the time the ESCV made the ESCV's 2006-10 EDPR and in South Australia and Queensland at the time of the AER's Final Determinations for those jurisdictions are more generous than the credit support arrangements currently applicable to Victorian DNSPs.

The credit support arrangement which was in place at the time of the ESCV's EDPR 2006-10, in particular, provided greater protection to Victorian DNSPs than that currently in place in Victoria. Under that arrangement DNSPs could request from a retailer the provision of credit support in the form of an undertaking for an amount not exceeding three months estimated distribution service charges where their credit rating was below BBB- and based on payment history.

This is the same arrangement which was in place in South Australia and Queensland at the time of the AER's Final Determinations for those jurisdictions (and continues to be in place in South Australia and Queensland) under the relevant standard Co-ordination Agreements. Under this arrangement retailers who are most likely to fail (i.e. retailers with a credit rating below BBB-) are required to provide full credit support.

[1055] The percentage of distributor's maximum credit allowance for a retailer with a credit rating of C is 0.1. Accordingly, the retailer's credit allowance would be calculated as 0.1 x 33.33 per cent = 0.033 per cent of annual distribution service charges revenue.
[1056] Letter from R Hermann to ESC dated 18 August 2006 in respect of ESC Credit decision (Attachment 225 to this Revised Regulatory Proposal).

17.5.2.4 No materiality threshold to apply to transmission related costs events

As set out in Chapter 3 of this Revised Regulatory Proposal, CitiPower proposes that the materiality threshold for the 'transmission related costs' event should be set at zero. The purpose of this pass through event is to ensure that CitiPower remains in the same position (and bears the same exposure to risk) that applied under the ESCV's 2006-10 EDPR and that would apply if Transmission-related Costs were recovered by adding a new term to the WAPC formula as proposed by CitiPower.

The ESCV's 2006-10 EDPR contains a K_t term to true up the difference between estimated and actual revenues and charges for embedded generation fees and inter-DNSP charges. CitiPower's proposed KAY_t term for the WAPC contains a similar true-up mechanism to ensure that there is no under or over recovery by DNSPs of Transmission-related Costs. Both of those mechanisms allow recovery of the full difference between actual and estimated costs and revenues, and do not contain any form of materiality threshold.

If the 'transmission related costs event' does not have a materiality threshold of zero, then the materiality threshold will result in a fundamental reassignment of risk from customers to DNSPs. The AER has not proposed any mechanism to compensate DNSPs for that increase in risk. It is not appropriate for the materiality threshold to result in such a reassignment of risk compared with the position under the ESCV's 2006-10 EDPR.

17.5.2.5 Pass through events in the Rules

In the AER's Queensland Final Determination, in response to an enquiry by Ergon Energy in its Revised Regulatory Proposal, the AER indicated that, as a guide, the AER is likely to give strong consideration to the adoption of a materiality threshold of one per cent of annual revenue for pass through events specified in chapter 10 of the Rules.[1057] CitiPower observes that the AER's assessment of whether a pass through event specified in the Rules is material must involve the objective application of the ordinary meaning of 'material'.

Chapter 10 of the Rules provides that outside of the application of transmission pass throughs in clause 6A.7.3 'materially' has its ordinary meaning. Clause 6.2.8(a)(4) of the Rules enables the AER to publish guidelines as to the AER's likely approach to determining materiality in the context of possible pass through events. However, the AER has not published any such guidelines and, more significantly, any such guidelines cannot alter the definition of materially in Chapter 10 of the Rules being that it has its ordinary meaning. Regardless of any guidance the AER provides on its general approach to assessing materiality whether in a distribution determination or guidelines under clause 6.2.8(a)(4), the AER has a duty to apply the ordinary meaning of 'material' on a case by case basis in assessing applications in respect of specific pass through events of the kind specified in Chapter 10 of the Rules. Neither the guidelines nor a distribution determination can change the meaning of 'material' in the Rules.

17.6 CitiPower's Revised Regulatory Proposal

CitiPower has revised its Regulatory Proposal to:

- include specific nominated pass through events for:
  - conditions or limitations imposed by ESV on provisional acceptance of an ESMS under the Electricity Safety Act;
  - transmission related costs event;

[1057] AER's Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), p310.

    - a natural disaster event;
    - an insurance event/legal liability above insurance cap event; and
    - an insurer credit risk event;
- have a materiality threshold for nominated pass through events (except for the financial failure of a retailer event and transmission related costs event) that the event has a material financial impact on the DNSP, with 'material' being interpreted according to its ordinary meaning. Having regard to CitiPower's annual revenue profile this would result in a materiality threshold for it of $250,000 over the regulatory control period for each nominated pass through event; and
- have no materiality threshold for the financial of a retailer and transmission related costs pass through events.

CitiPower's current Regulatory Proposal in respect of pass through is otherwise that set out in its Initial Regulatory Proposal. Since CitiPower proposed a RoLR pass through event in its Initial Regulatory Proposal and the AER accepted that proposal, CitiPower's Current Regulatory Proposal includes that event.

18. BUILDING BLOCK REVENUE REQUIREMENTS

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapter 18 of the Draft Determination regarding CitiPower's building block revenue requirements.

18.1 Summary of key points

This Chapter sets out CitiPower's proposed ARRs and X factors for 2011-15.

18.2 Rules requirements

Clause 6.4.3 of the Rules requires the application of a building block approach to determine the ARRs 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 EBSS, the STPIS, and the DMIS; and
- other revenue adjustments (if any) arising from the application of the control mechanism in the previous regulatory control period; and
- forecast opex.

The development of each of these building blocks has been described in earlier chapters of this Revised Regulatory Proposal.

Clause 6.5.9(b) of the Rules provides that a building block determination is to include the X factor for each control mechanism for each regulatory year of the regulatory control period.

Clause 6.5.9(b) of the Rules requires the X factors to be set:

- with regard to the proposed total revenue requirement;
- to minimise, as far as reasonably possible, the variance between expected revenue for the last regulatory year of the regulatory control period and the ARR for that last regulatory year; and
- to equalise (in terms of NPV) 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.

Clause 6.4.3 of the Rules defines 'annual revenue requirement' as comprising the following building blocks:

- indexation of the RAB;
- a return on capital for that year;
- the depreciation for that year;
- the estimated cost of corporate income tax of the provider for that year;

- the revenue increments or decrements (if any) for that year arising from the application of the EBSS, the STPIS and the DMIS;
- the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period; and
- the forecast opex for that year.

18.3 CitiPower's Initial Regulatory Proposal

In the Initial Regulatory Proposal, CitiPower proposed the ARRs set out in Table 18.1 below.[1058]

	$m (nominal)				
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
Opex	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 18.1 Initial Regulatory Proposal - Annual revenue requirements

CitiPower's proposed X factors for standard control services as set out in the Initial Regulatory Proposal are summarised in Table 18.2 below.[1059]

	2011	**2012**	**2013**	**2014**	**2015**
X factors (per cent)	(10.1)	(8.0)	(8.0)	(8.0)	(8.0)

Table 18.2 Initial Regulatory Proposal - Proposed X factors

18.4 AER's Draft Determination

In the Draft Determination, the AER determined that CitiPower's ARRs and X factors should be as set out in Table 18.3.[1060]

[1058] Initial Regulatory Proposal, p320.
[1059] Initial Regulatory Proposal, p321.
[1060] AER, Draft Determination, p767.

Table 18.25 AER conclusion on CitiPower's revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		124.5	133.8	142.6	152.0	158.6
Regulatory depreciation		35.2	38.4	41.9	45.6	49.6
Operating expenditure		36.7	37.7	39.5	42.0	43.4
Efficiency carryover amounts		5.6	–7.2	–4.9	–5.2	0.0
S factor amounts		0.2	–3.0	–3.6	–0.2	–7.8
Tax allowance		6.0	6.3	6.6	6.6	6.8
Annual revenue requirements		208.2	206.0	222.0	240.8	250.6
Expected revenues	211.8	205.0	215.1	223.2	234.7	248.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		7.27	0.00	0.00	–2.00	–2.00

Note: Positive values for X indicate real price decreases under the CPI–X formula.
Source: PTRM.

Table 18.3 Draft Determination - Annual revenue requirements and X factors

18.5 CitiPower's response to the AER's Draft Determination

CitiPower has set the X factors such that:

- they are the same value for each regulatory year from 2012-15; and
- the variance between the expected revenue for the last regulatory year of the regulatory control period and the ARR for that last regulatory year is less than 6%.

On the basis of the previous chapters of this Revised Regulatory Proposal, CitiPower's proposed ARRs and X factors are as set out in Tables 18.4 and 18.5.

	$m (nominal)				
Building block	**2011**	**2012**	**2013**	**2014**	**2015**
Indexation of the RAB	(33.1)	(37.1)	(41.3)	(46.1)	(50.8)
Return on capital	132.6	148.6	165.6	184.7	203.4
Depreciation	67.9	75.7	84.0	93.0	103.2
Opex	52.7	54.4	57.6	59.1	63.4
Corporate income tax	4.2	4.6	5.5	5.9	6.9
Efficiency carryover mechanism	0.0	0.0	0.0	0.0	0.0
Service incentive mechanism	0.2	(2.9)	(3.4)	(0.2)	(7.3)
Total	**224.4**	**243.4**	**267.9**	**296.4**	**318.7**

Table 18.4 Proposed ARRs

	2011	2012	2013	2014	2015
X factors (per cent)	-7.21%	-4.00%	-4.00%	-4.00%	-4.00%

Table 18.5 Proposed X factors

18.6 CitiPower's Revised Regulatory Proposal

CitiPower amends its Initial Regulatory Proposal to propose the ARRs and X factors set out in Tables 18.4 and 18.5.

19. ALTERNATIVE CONTROL SERVICES (INCLUDING PUBLIC LIGHTING)

In this Chapter of the Revised Regulatory Proposal, CitiPower responds to Chapters 19 and 20 of the AER's Draft Determination in respect of public lighting and alternative control services. Specifically, this Chapter deals with the AER's Draft Determination in respect of:

- alternative control fee based services;
- alternative control quoted services; and
- public lighting services.

19.1 Summary of key points

CitiPower submits that the AER should determine its prices for fee based and quote based alternative control services on the basis that CitiPower should be permitted to recover its efficient costs of providing alternative control services. CitiPower is not able to recover those costs on the basis of its existing charges or the charges proposed in the AER's Draft Determination.

Accordingly, CitiPower has made revisions to the alternative control services model used by the AER for the purposes of its Draft Determination[1061] in order to facilitate recovery of its efficient costs of providing alternative control services. In CitiPower's view, the AER should accept CitiPower's proposed labour rate, times to perform activities, profit margin and contract rates described in this Revised Regulatory Proposal.

In addition, the AER should revise its Draft Determination in respect of public lighting to:

- apply the general materials escalator that CitiPower has used for its standard control services to materials other than poles and brackets;
- accept the costs for poles and brackets, patrol vehicles, traffic management and luminaires set out in this Revised Regulatory Proposal; and
- apply the failure rate for T5 (2x14W) lights set out in this Revised Regulatory Proposal.

19.2 Rule requirements

Clause 6.12.1 of the Rules sets out the constituent decisions of the AER on which a distribution determination is predicated. In respect of the control mechanism for alternative control services, those decisions include:

- a decision under clause 6.12.1.(12) on the control mechanism for alternative control services (to be in accordance with the relevant framework and approach paper); and
- a decision under clause 6.12.1(13) on how compliance with a relevant control mechanism is to be demonstrated.

[1061] Provided to CitiPower on 7 June 2010.

19.3 Fee Based Services

19.3.1 Initial Regulatory Proposal

In Chapter 23 of its Initial Regulatory Proposal, CitiPower described its charging methodology for fee based services in the next regulatory control period and the application of the control mechanism for fee based services.[1062]

It observed that 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 applied the AER's control mechanism for fee based services by:

- 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 applied to the following services: wasted attendance - not DNSP fault, service truck activities, supply abolishment, fault response - not DNSP fault and various meter testing; and
- 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 applied to the following services: disconnection, reconnection, special reading, various meter testing, meter investigation and PV installation.

At a meeting with the AER on 18 February 2010, the AER requested CitiPower to provide it with bottom up cost build ups for all alternative control services. Accordingly, in response to the AER's request CitiPower was required to provide a bottom up approach to determine price caps for all alternative control services and on 3 March 2010, CitiPower provided the AER with a bottom up cost model, containing cost build ups for all fee based alternative control services.

The cost build-up model for alternative control services included labour and materials costs. The labour costs were determined by the labour rate and the time taken to perform the tasks associated with performing the service. CitiPower's labour rate inputs were generated using contractor costs.

The cost build up model summed the total internal and external costs of providing the service. A profit margin was then added to derive the final price. A profit margin was included to reflect that without a return, the DNSPs would not have an incentive to provide alternative control services.

19.3.2 AER's Draft Determination

The AER engaged Impaq to assist its review of the proposed charges for alternative control services, in particular the inputs of hourly labour rates, materials and times taken to perform

[1062] Initial Regulatory Proposal, pp367-80.

the services. Impaq prepared a report entitled *Impaq Consulting, Review of Distributors Proposed Rates in ACS Charges*.[1063]

The AER rejected CitiPower's proposed fee based alternative control service prices. For the purposes of its Draft Determination, the AER made revisions to the model provided to it by CitiPower on 3 March 2010. The AER provided its model to CitiPower on 7 June 2010.

19.3.2.1 Labour inputs

The AER stated that Impaq's analysis of labour rate inputs found that, compared to DNSPs in other jurisdictions and the 2009 NECA survey of industry charge out rates, CitiPower's business hours line worker rates were high.[1064]

Impaq considered a reasonable labour charge out rate range for line workers (business hours) was between $74 and $84 per hour ($2010). Impaq considered a reasonable charge out rate for line workers (after hours) was between $84 and $105 per hour ($2010).

The AER considered that CitiPower's proposed hourly labour rates for line workers in business and after hours times were significantly higher than industry standards.[1065] The AER determined that the highest point of Impaq's range of labour charge out rates, adjusted to allow a 3 per cent profit margin should be applied to CitiPower's hourly rates for business and after hours line workers. Accordingly, the AER applied a labour rate of $79.80 per hour (business hours) and $99.75 per hour (after hours).

19.3.2.2 Contract rates

The AER considered that the service provider's 2011 contract rates for CitiPower's reconnection, disconnection and special meter read services were reasonable.[1066] However, the AER did not consider that the escalation of the service provider's rates over 2012-15 was sufficiently justified.[1067]

19.3.2.3 Times required per activity

Having regard to Impaq's Report, the AER determined that in building up the costs for the top seven services CitiPower had significantly overstated the times needed for many labour components.[1068] The AER considered that Impaq had provided a reasonable range of times in which the various components of each service could be expected to perform. It decided that where Impaq had found CitiPower's times to be outside a reasonable range, it was appropriate to apply the highest point of Impaq's recommended times for the services.

In order to derive draft determination prices for services for which Impaq did not provide recommended times, the AER determined the times based on the description of the task and the times recommended by Impaq for similar tasks. The AER also applied Impaq's recommended labour rates, adjusted to include a 3 per cent profit margin.[1069]

[1063] References to Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010 in this Revised Regulatory Proposal are references to its report reference – '*impaq final report – cp and pc confidential version (D2010-03621655).DOC'* (Attachment 227 to this Revised Regulatory Proposal).
[1064] AER, Draft Determination, p854.
[1065] AER, Draft Determination, p855.
[1066] AER, Draft Determination, p855.
[1067] AER, Draft Determination, p855 and 863.
[1068] AER, Draft Determination, p858.
[1069] AER, Draft Determination, p858.

19.3.2.4 Profit Margins

The AER referred to Impaq's discussion on the profit margin for alternative control services. The AER noted that the profit margin within Impaq's recommended high case charge out rates was 8 per cent. It noted that Impaq had stated that:[1070]

> *'Alternative control services are not capital intensive and hence the application of the standard building blocks of Return of Capital and Return on Capital do not yield meaningful profit margins. However in similar service industries profit margins of 3% to 8% are common. Given the low risk nature of the revenue earned by the DNSPs for ACS services it is arguable that margins should be at the lower end of the range.'*

The AER considered that the maximum allowable profit margin that should be applied to alternative control services is 3 per cent. Accordingly, the AER amended the Impaq high case labour charge out rates by removing 5 per cent. The AER applied the adjusted ranges of labour charge out rates and Impaq's recommended range of time inputs in a cost build up to determine a reasonable range of prices for each service.

The AER considered that it was inefficient for CitiPower to earn an additional margin on alternative control services when the DNSPs do not actually provide, nor add any identifiable value to, the services. Accordingly, the AER removed the additional margin applied by CitiPower to its alternative control service charges for 2011.[1071]

19.3.2.5 Labour and materials escalators

In determining prices for fee based alternative control services, the AER applied the labour and materials escalators it approved for standard control services set out in Appendix K of its Draft Determination.[1072]

19.3.2.6 Price path – fee based services

The AER found that CitiPower's proposed prices for reconnection and disconnection services and special meter reads increased significantly by between 77 per cent and 94 per cent over the forthcoming regulatory control period.[1073]

CitiPower had informed the AER that this was the result of a doubling of their service provider's contract rate for field site crew for these services. The AER considered that this price increase had not been adequately justified and requested CitiPower to provide a more detailed breakdown of their service provider's contract rates for 2010-15, including hourly labour rates, and a detailed breakdown of the activities being performed in the provision of each service.

The AER said that in the absence of supporting information, it did not approve CitiPower's proposed prices for 2012-15 in the Draft Determination. It also considered that CitiPower's proposal for individual prices for each year of the forthcoming regulatory period was inconsistent with a price path based on a CPI-X control mechanism required by the Framework and Approach Paper. The AER asked CitiPower to submit price paths consistent with the Framework and Approach Paper for their fee based alternative control services. The AER considered that the price paths should incorporate the labour and

[1070] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p39.
[1071] AER, Draft Determination, p861.
[1072] AER, Draft Determination, p862.
[1073] AER, Draft Determination, p862.

materials escalators the AER approved for standard control services in Appendix K of its Draft Determination.

19.3.2.7 Changes to service classification

The AER asked CitiPower to provide the following information in respect of prices which CitiPower did not classify as alternative control services in its Initial Regulatory Proposal, but which the AER classified as fee based alternative control services in its Draft Determination:[1074]

- Reserve feeder service. CitiPower proposed this service as a negotiated service. The AER classified this service as an alternative control fee based service. The AER required CitiPower to propose a fee for this service.
- Re-test of type 5 and 6 meters service. CitiPower proposed this service as a standard control service. The AER classified this service as an alternative control fee based service. The AER required CitiPower to propose a fee for this service.
- Fault level compliance service. CitiPower proposed this service as a standard control service, and proposed to charge embedded generators a one off capital contribution of $625 per kWh ($2009). The AER classified this service as an alternative control fee based service. The AER requested CitiPower to provide further information to support the fee as an alternative control service fee as part of its Revised Regulatory Proposal.

19.3.3 CitiPower's response to AER's Draft Determination

19.3.3.1 CitiPower's revised model

CitiPower submits that the AER should determine its prices for fee based and quote based alternative control services on the basis that CitiPower should be permitted to recover its efficient costs of providing alternative control services. CitiPower is not able to recover those costs on the basis of its existing charges or the charges proposed in the AER's Draft Determination.

Accordingly, CitiPower has made revisions to the alternative control services model used by the AER for the purposes of its Draft Determination[1075] in order to facilitate recovery of its efficient costs of providing alternative control services. CitiPower provides its revised model as an attachment to this Revised Regulatory Proposal.[1076]

CitiPower's proposed charges for fee based alternative control services are set out in Appendix 9.1 to this Revised Regulatory Proposal.

The revisions made to the AER's alternative control service model are based on CitiPower's view that the AER's, and Impaq's, criticisms of the model which CitiPower provided to the AER on 3 March 2010 are incorrect in relation to following matters:

- profit margins;
- contract rates;
- labour rates for line workers; and
- times required per activity.

[1074] AER, Draft Determination, p864.
[1075] Provided to CitiPower on 7 June 2010.
[1076] Attachment 19 to this Revised Regulatory Proposal.

The following sections describe where CitiPower considers the AER and Impaq have made incorrect assumptions, why they have made an error, and what the correct assumptions should be.

Profit margins

In determining a profit margin of 3 per cent the AER relied on Impaq's Report and its statement that given the low risk nature of the revenue earned by the DNSPs for alternative control services, it is arguable that margins should be at the lower end of the range of 3 per cent to 8 per cent.[1077]

It is unreasonable for the AER to rely on Impaq's Report.

In determining the range of profit margins, Impaq stated that *'in similar service industries profit margins of from 3% to 8% are common'*.[1078] In support, Impaq said:[1079]

> '*Some instances are: United Group Limited, which provides services across several industries including electricity, have historically achieved net profit margins of about 5%. Refer UGL annual reports. Norfolk (which includes O'Donnel Griffin electrical contracting) has an EBIT margin of 3% in recent years. Downer EDI 5%, Leightons 7.5%.'*

Impaq quoted Norfolk to have an EBIT margin of 3 per cent. However, a Norfolk presentation of its financial results for the year ended 31 March 2010 dated 26 May 2010 shows that the Electrical & Communications Division of Norfolk had an EBIT profit margin of 5.7 per cent in 2009 and 5.8 per cent in 2010.[1080] CitiPower observes that this profit margin is more closely aligned with the profit margins for Downer EDI and Leightons referred to by Impaq.

CitiPower proposes that the AER should use Norfolk's Electrical & Communications Division's EBIT profit margin of 5.7 per cent as an appropriate margin for the purposes of its Final Determination. CitiPower has revised the AER's alternative control model to include a profit margin of 5.7 per cent.

In addition to the amount of the AER's profit margin, CitiPower asserts that the AER's methodology for calculating the adjustment to the labour rate to account for the profit margin is erroneous and causes the labour rate to be lower than it should otherwise be. The AER calculated this adjustment as:

- $84.00 – ($84.00 × 0.05) = $79.80

The AER adjusted the labour rate by subtracting 5 per cent of the final rate therefore overstating the profit margin and reducing the labour rate by more than it should have. Instead, on the basis of the AER's profit margin of 3 per cent, the AER should have calculated the adjustment to the labour rate as follows:

- $84.00 ÷ 1.08 × 1.03 = $80.11

However, CitiPower asserts that the correct profit should be 5.7 per cent and therefore the correct adjustment to the labour rate the AER used should be:

[1077] AER Draft Determination, p852.

[1078] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p38.

[1079] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p38, footnote 17.

[1080] Norfolk, Financial Results for the Year Ended 31 March 2010, presentation dated 26 May 2010, (Attachment 229 to this Revised Regulatory Proposal), p15.

- $84.00 ÷ 1.08 × 1.057 = $82.21

Contract rates

The AER did not consider the escalation of the service provider's contract rates over 2012-15 for reconnection, disconnection and special meter read services was sufficiently justified.[1081] It requested CitiPower to provide a more detailed breakdown of their service provider's contract rates for 2010-15, including hourly labour rates, and a detailed breakdown of the activities being performed in the provision of each service.

In response, CitiPower provides the AER with the CHED Services Conditions of Contract for the Supply of Cyclic Field and Special Meter Reading Services as an attachment to this Revised Regulatory Proposal.[1082] Schedule 3 of the contract with the service provider, AMRS, states that both *'parties agree to negotiate pricing, in good faith and review the Advanced Metering Infrastructure rollout impact as volumes decrease significantly'*.[1083]

A presentation prepared by AMRS in October 2009 discusses the uncertainty associated with the impact of the AMI rollout and proposes the following rate increases based on expected volume reduction.[1084]

Year	2011	2012	2013	2014	2015
Rate increase	20%	50%	100%	100%	100%

Table 19.1 AMRS rate increases

This shows that CitiPower's escalation of the service providers rates over 2012-15 is justified. CitiPower has revised the AER's alternative control services model to escalate service providers rates in the manner proposed in the model it provided to the AER on 3 March 2010.[1085]

Labour rates for line workers

In determining the labour rate for line workers to apply to CitiPower's fee based alternative control services and quote based alternative control services, the AER relied on Impaq's Report.

CitiPower submits that Impaq's Report cannot be relied upon to determine the labour rates for line workers because Impaq's methodology for determining the labour rates in its report is erroneous.

In the model it provided to the AER on 3 March 2010, CitiPower provided fully cost absorbed labour rates of $120.01 per hour (business hours) and $131.97 per hour (after hours) exclusive of margin. CitiPower's labour rate inputs were generated using contractor costs.

Impaq's view of the labour rate for line workers was determined by:[1086]

[1081] AER, Draft Determination, p855.
[1082] CHED Services Contract with AMRS for the Supply of Cyclic Field and Special Meter Reading Services (Attachment 231 to this Revised Regulatory Proposal).
[1083] CHED Services Contract with AMRS for the Supply of Cyclic Field and Special Meter Reading Services, (Attachment 231 to this Revised Regulatory Proposal), p59.
[1084] Servicestream, Presentation - Working Together CitiPower/Powercor Contract Variations October 2009, (Attachment 239 to this Revised Regulatory Proposal), p8.
[1085] See CitiPower's revised model for alternative control services (Attachment 19 to this Revised Regulatory Proposal.
[1086] AER, Draft Determination, p3.

- applying a bottom up build for labour rates which involved calculating a charge-out rate based on wage rates, available hours, on-costs, overheads and a profit margin;
- comparing the labour rates provided by Powercor Australia, CitiPower and Jemena in their regulatory proposals to rates published by ETSA, Country Energy and Energy Australia, rates included in DNSP's submissions for other distribution price determinations and the AER's Energy Australia Draft Distribution Determination 2009-10 to 2013-14 Alternative Control (public lighting) services; and
- considering benchmarked rates from the National Electrical and Communications Association.

In determining the wage rates for line workers to input into its bottom up build, Impaq had regard to salaries advertised in job advertisements across several states on Seek, MyCareer, Jobseeker and Career One.[1087] The advertised salaries cannot give a reliable indication of the actual salary because the advertised salary is merely an offered rate. It does not represent the rate accepted by the job applicant which is likely to be higher following negotiations with the employer. Additionally Impaq's references to advertised salaries cannot be substantiated by evidence and therefore does not give CitiPower an opportunity to verify Impaq's conclusions.

Impaq also had regard to Hays' salary survey for 2009.[1088] Again, this is not an appropriate comparator. Impaq's review of Hays' salary survey made assumptions about the category of employee and the business sector in which they worked. Consequently Impaq considered salaries ranging from $60,000 to $70,000 in the manufacturing and operations sector as appropriate. The businesses categorised as 'manufacturing and operations' cover a broad range of business types and are therefore not directly comparable to CitiPower. Further, Hays' salary survey specifically states that '*[s]ome niche markets however continue to see positive growth, in particular …utilities*'[1089] indicating salaries in this sector are higher than the average.

Hays has released a salary guide specific towards distribution businesses that reports salaries in the range of $70,000 to $85,000 for electricians in Victoria, which is well above that which Impaq have reported.[1090]

In determining the available hours component of its bottom up build, Impaq made the following incorrect assumptions:[1091]

- it incorrectly assumed a 7.5 hour work day. The number of hours mandated by the CEPU Workplace Agreement is 7.2 hours per day (36 hours per week) and a 36 hour week is common to Victorian DNSPs;1092
- it incorrectly assumed 10 public holidays in 2010. There were actually 11 public holidays in Victoria in 2010. There were 12 public holidays for CitiPower under its CEPU work agreement; and

[1087] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p34.
[1088] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p35.
[1089] Extract from Hays' salary survey 2009, *Sector Commentary, Manufactoring & Ops*, (Attachment 235 to this Revised Regulatory Proposal), p118.
[1090] Hays, *Hays Salary Guide* 2010, (Attachment 237 to this Revised Regulatory Proposal), p121.
[1091] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p37.
[1092] CitiPower (CEPU) Workplace Agreement 2007 (attachment number C0037 to the Initial Regulatory Proposal).

- it does not include non-chargeable time, for example:
  - Training;
  - Work group meetings;
  - OHS meetings for representatives;
  - Union meetings;
  - Jury service.

In making the comparison between CitiPower's proposed rates and the rates for interstate distribution businesses[1093], Impaq failed to account for different cost allocation methods used by the distribution businesses. Different distribution businesses have different methods for allocating costs between their different services. For example, some distribution businesses apportion costs and overheads to standard control which may be properly classified as relating to alternative control services. It is probable that the difference between the labour rate proposed by CitiPower and the labour rate proposed by other distribution businesses can be explained by different cost allocation methods.

Further, in making this comparison Impaq used an incorrect labour rate for ETSA and inappropriate labour rates for Country Energy and Energy Australia. Impaq used a labour rate for ETSA of $84 which was purportedly taken from its Standard Fees publication.[1094] This figure is incorrect. Rather, ETSA's 'Network Tariff and Negotiated Services, June 2010' publication reveals a labour rate of $100 for comparable services.[1095] Impaq used Country Energy's and Energy Australia's labour rates for their miscellaneous services effective 1 July 2009.[1096] These labour rates are not comparable with CitiPower's labour rate because CitiPower's labour rates are effective in mid 2010 and therefore there is a one and a half year lag in Country Energy's and Energy Australia's real labour rates. In addition, the labour rates for Country Energy and Energy Australia relied on by Impaq are not for line worker labour, but rather are for a different class of labour (Inspector R2b) and therefore are not comparable. Further, in response to an enquiry from CitiPower, Energy Australia has advised that the rate in question was not necessarily reflective of costs to undertake the prescribed activities.

Accordingly, the AER cannot rely on Impaq's Report in determining the labour rate for line service workers. CitiPower submits that the AER should accept the labour rates ($2010) of $120.01 per hour (business hours) and $131.97 per hour (after hours) which were included in the model CitiPower provided to the AER on 3 March 2010. Accordingly, CitiPower has included these labour rates in its revised alternative control services model.

Time required per activity

The AER relied on Impaq's Report in determining the times in which the various components of each service could be expected to perform. As noted above, it decided that where Impaq had found CitiPower's times to be outside a reasonable range, it was appropriate to apply the highest point of Impaq's recommended times for services.

[1093] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p45 and 49.

[1094] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p40.

[1095] ETSA, *Network Tariff & Negotiated Services*, June 2010, (Attachment 236 to this Revised Regulatory Proposal) p63.

[1096] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), pp40-1.

CitiPower submits that the AER cannot reasonably rely on Impaq's time estimates or comments in respect of CitiPower's time estimates. Impaq's time estimates and comments are not supported by any evidence.

Accordingly the AER should use the times taken to perform services provided in CitiPower's revised alternative control services model as described below. Unlike Impaq's time estimates which are completely unsubstantiated those times are supported by CitiPower's actual operations.

CitiPower responds below to Impaq's comments in respect of the following times to perform services in section 8 of its Report:[1097]

- field officer visits special reads BH (service number 1 in Impaq's table);
- service vehicle visit BH and AH (service numbers 7 and 8 in Impaq's table); and
- field staff times for meter equipment tests (service numbers 11-18 in Impaq's table).

<u>Field Officer Visits Special Reads BH</u>

In respect of field officer visits special reads, Impaq considered in section 8 of its Report (service 1 in its table) that the back office times '*should be an automated B2B service not requiring manual intervention expect in rare circumstances*'. Impaq then proposed a maximum time of 0.03 hours. CitiPower has reviewed its time in line with actual reported information and considers that Jemena's allocation of 0.042[1098] is more in line with CitiPower's actual time allocation than the unsupported estimate provided by Impaq. Accordingly, CitiPower has used this time in its revised alternative control services model.

<u>Service vehicle visits BH and AH</u>

In respect of service vehicle visits, Impaq considered in section 8 of its Report (services 7 and 8 in its table) that:[1099]

- back office times appear excessive;
- field staff times appear excessive; and
- scheduling team time looks too high.

In respect of back office time for 'service visit BH & AH, Impaq stated that:[1100] *'These back office times appear excessive as this is just about booking a truck to come to the customers site, then doing a wrap up on the job when completed. It would have been expected that 0.3 hours would be adequate.'* CitiPower's back office times have been obtained from its actual reported information. The tasks identified for each service were timed using a stopwatch. Accordingly, these times should be preferred to any unsubstantiated times provided by Impaq in its Report.

In respect of field staff time for 'service vehicle visit BH & AH', Impaq said that[1101] '*CitiPower have assumed a travel time of 45 min which seems excessive as a travel time*

[1097] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), pp51-4.
[1098] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51, service 1.
[1099] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.
[1100] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.
[1101] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.

between jobs. It would be expected that this would be more like 20 mins. It would be expected that this would be more like 20 mins. Total travel time here would be expected to be about 2.7 hours - 1 hour on site for crew of 2 plus 20 min travelling time for crew of 2.'

While Impaq states that '*CitiPower has assumed a travel time of 45 min*', this is incorrect. In its Initial Regulatory Proposal CitiPower assumed a travel time of 44 minutes. This travel time was obtained from a trial undertaken in 2007 by metering operations group technicians recording their travel time to and from jobs. This trial was checked against a number of technicians actual travel times between jobs and it averaged out at 44 minutes. CitiPower's travel time is also comparable to Powercor Australia's travel time data, taking into consideration the fact that travel times for CitiPower are likely to be higher than those for Powercor Australia given greater traffic congestion in urban areas.

Powercor Australia's travel times data shows that the average travel times per job for each of the years 2005-07 were those as set out in the following table. This data comes from confirmed travel times in its project management orders compared to the number of jobs completed over the years. While this data is for Powercor Australia, it supports CitiPower's travel time of 44 minutes.

Year	Total Number of Jobs	Total Manhours for Travel	Average Travel time per job
2007	19,310	14,188	44mins (14,188/19,310x60)
2006	23,711	17,666	45mins (17,666/23,711x60)
2005	22,903	16,528	43mins (16,528/22,903x60)

Table 19.2 Travel Time Data 2006-07

The source spreadsheets for these travel times are provided as an attachment to this Revised Regulatory Proposal.[1102]

In respect of scheduling team time for 'service visits BH and AH', Impaq stated that[1103] '*these times together with the back office times look too high. To allow 15 min to 20 min to schedule a truck visit seems high. 5 min would be more reasonable'*.

CitiPower's proposed times are supported through time confirmations within its job tracking software (SAP).[1104]

<u>Field staff times for meter testing</u>

In respect of field staff time for 'meter equipment test – single phase BH&AH' and 'meter equipment test – multi phase BH&AH' (items 11, 12, 14 & 15 in Impaq's Report), Impaq said that[1105] '*Back office times for PC/PC seem excessive. This is just to receive the request from B2B service order and schedule the testing then report results. It is expected that this should be less than 25min'*. CitiPower's back office times have been obtained from its internal records. The tasks listed for each service were timed using a stopwatch. Accordingly, these times should be preferred to any unsubstantiated times provided by

[1102] Source spreadsheets for Powercor Australia's travel times (three worksheets for 2005, 2006 and 2007) (Attachment 228 to this Revised Regulatory Proposal).

[1103] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.

[1104] SAP stands for Systems Analysis and Program and is business management software used by CitiPower.

[1105] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.

Impaq in its Report. Accordingly, CitiPower has used the times proposed in the model it provided to the AER on 3 March 2010 in its revised alternative control services model.

In respect of field staff time for 'meter equipment test – single phase BH&AH' (items 9 and 10 in Impaq's Report), Impaq said that[1106] '*Testing times seem excessive. Eg: Isolating supply at 10 min is excessive for just having to pull the service fuse. Eg. Allowance of 45 min to test meter is excessive. Overall times could be reduced by about 50%.*'.

CitiPower observes that part of the process of isolating supply is job preparation and safety assessment. The safety assessment is undertaken using CitiPower's Specialist Metering Check List.[1107] Once all site safety issues have been considered, there are three areas of isolation: (i) fuse on the meter board (one stick required); (ii) fuse at overhead service connection; and (iii) fuse at overhead service connection (multiple sticks required). Sticks are secured on the vehicle and need to be obtained and taken to the isolation point. CitiPower confirms that the time taken to perform the task of isolating supply is 10 minutes.

The times to test a meter which CitiPower provided were built up around an average of dial tests for mechanical meters, electronic meters and interval meters.

- The time allocation for a dial test for a mechanical meter is 20 minutes. At least 1Kwh needs to be recorded on the meter register;
- The time allocation for electronic meters is 20 minutes. There are multiple registers (ie Peak and Off Peak) to consider.
- The time allocation for an interval meter is 35 minutes. One full 30 minute interval needs to be compared with the meter registers. Further software is required to download meter interval data after the dial test period and compare it to actual readings on meter registers.

The time calculation in the following table is based on averaging out the number of mechanical meters, electronic meters and interval meters.

[1106] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.
[1107] CitiPower's Specialist Metering Checklist (Attachment 240 to this Revised Regulatory Proposal)

Test	Time taken to perform test
Registration Test AV	12 minutes
Remove Customer Load/s	2 minutes
Creep Test	5 minutes
Light Load Test	5 minutes
Light Load Test 0.5pf	7 minutes
Full Load Test	2 minutes
Full load test 0.5pf	4 minutes
Temperature & Voltage tests	2 minutes
Reconnect Customer Load/s	2 minutes
Total time	**41 minutes**

Table 19.3 Time taken to perform meter equipment test – single phase BH & AH

CitiPower has used these times in its revised alternative control services model.

In respect of field staff time for 'meter equipment test – single phase – each additional meter' and 'meter equipment test – multiphase – each additional meter' (service number 13 & 16 in the table in Impaq's Report), Impaq states that:[1108] '*This time includes all activities as if it were the only meter being tested. This should be reduced to no more than 25 min.*'

The meters are tested in series, not in parallel. Additionally the time allocated is specific to the type of meter being tested. The activities involved and the times taken for this test are set out in the following tables:

Test	Time taken to perform test
Connect Test Set	10 minutes
Perform Test	41 minutes
Disconnect Supply/Test Set	10 minutes
Reconnect Supply	5 minutes
Total time	**66 minutes**

Table 19.4 Time taken to perform meter equipment test – single phase each additional meter

[1108] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.

Test	Time taken to perform test
Connect Test Set	10 minutes
Perform Test	90 minutes
Disconnect Supply/Test Set	10 minutes
Reconnect Supply	5 minutes
Total time	**115 minutes**

Table 19.5 Time taken to perform meter equipment test –multi phase each additional meter

CitiPower has used these times in its revised alternative control services model.

In respect of field staff time for meter equipment test – current transformer multi phase BH & AH (services number 15 and 16 in Impaq's Report), Impaq states that:[1109] '*Testing a CT connected meter is more complicated however the times proposed by CP/PC seem excessive*'.

CitiPower observes that a current transformer (CT) meter is connected to instrument transformers via a 'wiring loom'. As well as performing the meter test the following tests/checks also need to be undertaken to confirm that all metering components are operating correctly.

[1109] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.

Test/check	Description of test/check
Metering/current transformer circuit burden test	The current transformer terminal voltage and current is measured to enable a connected burden in Ohms calculation to be undertaken in order to ensure the current transformer is operating within its connected burden specification.
Admittance testing (condition monitoring) of current transformers	An admittance tester is used to check the current transformer's admittance value. This value is compared to the previous admittance test results to determine if the current transformer has 'changed state', which may affect its accuracy.
Current transformer ratio comparison checks	All current transformers are based on a ratio of a primary to secondary value. For example, if a current transformer is rated at 200/5, a ratio of 40 is applied to the secondary readings to determine the primary readings for KWh usage.
Primary to secondary and maximum demand tests	The primary currents and secondary currents are checked to ensure correct ratio and output of current transformers. The maximum demand of the installation is calculated over a 30 minute period to compare with a 30 minute interval maximum demand reading recorded by the current transformer meter.
Individual phase voltage and current tests	Each phase voltage and current is checked to ensure current transformers are not overloaded.
confirming individual phase voltage and phase current relationship	Phase voltages and currents are checked to ensure phase currents and voltages are correctly associated in order to ensure the correct operation of the meter.

Table 19.6 Meter tests/checks

Given the tests/checks that are required to be undertaken, the time proposed by CitiPower is not excessive. Accordingly, CitiPower has used the times proposed in the model it provided to the AER on 3 March 2010 in its revised alternative control services model.

19.3.3.2 Price path fee based services

The AER has asked CitiPower to submit price paths consistent with the Framework and Approach Paper for its fee based alternative control services. The AER considered that the price paths should incorporate the labour and materials escalators the AER approved for standard control services in Appendix K of its Draft Determination[1110]. However, for the

[1110] AER, Draft Determination, p863.

reasons set out in Chapter 8 of this Revised Regulatory Proposal, CitiPower asserts that the appropriate labour and materials escalators are those set out in Chapter 8.

CitiPower has determined an X factor for fee based services by applying the weighted average real labour and material escalators in Chapter 8 of this Revised Regulatory Proposal and expected real contract rate increase over the 2012-15 period for all fee based alternative control services. These X factors are set out in the following table.

Year	2012	2013	2014	2015
X factor	(37.4)%	(27.2)%	(0.3)%	(0.2)%

Table 19.7 X factor for fee based connection services (real)

Year	2012	2013	2014	2015
X factor	(0.9)%	(1.9)%	(2.6)%	(1.6)%

Table 19.8 X factor for other fee based services (real)

19.3.3.3 Changes to service classification

The AER asked CitiPower to provide information in respect of prices for services which CitiPower did not classify as alternative control services in its Initial Regulatory Proposal, but which the AER classified as alternative control services.[1111]

Using the approach to determining alternative control charges proposed by CitiPower in this Revised Regulatory Proposal, CitiPower has proposed fees for the re-test of type 5 and 6 meters service and reserve feeder services in the forthcoming regulatory control period in Appendix 19.1.

As set out in Chapter 2 of this Revised Regulatory Proposal, CitiPower has decided not to provide the fault level compliance service. Accordingly, it has not provided any information to support an alternative control service fee as part of its Revised Regulatory Proposal.

19.4 Quote Based Services

19.4.1 CitiPower's Initial Regulatory Proposal

In Chapter 23 of its Initial Regulatory Proposal, CitiPower described its charging methodology for quoted alternative control services in the next regulatory control period and the application of the control mechanism for quoted services.[1112]

It stated that it intended to continue to apply its current methodology for developing its charges for quoted alternative control services in the next regulatory control period. This method involves recovering the costs of both labour and materials. Unlike the charges for fee based services, the charges for quoted alternative services are developed on a case by case basis in order to meet the specific needs of the customer.

[1111] AER, Draft Determination, p864.
[1112] Initial Regulatory Proposal, pp381-88.

CitiPower quantified its labour costs for each quoted service by specifying the relevant labour rate for the skill set involved. To the extent materials are involved, CitiPower considered that they would be charged at cost.

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 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 applied the AER's control mechanism for quoted services by:

- determining the price caps that are to apply to the labour rates that it would use to determine its charges for quoted services; and
- applying a CPI-X adjustment to the labour rates for years two to five of the next regulatory control period.

19.4.2 AER's Draft Determination

19.4.2.1 Materials

The AER considered that customer prices for materials for quoted services should be set at the cost of the materials to DNSPs.[1113]

19.4.2.2 Labour rates

The AER observed that in comparing CitiPower's proposed quoted services labour rates to the charge out rates for line workers, Impaq found CitiPower's labour rates to be above the reasonable range.[1114] Consistent with its approach to fee based services, the AER considered a reasonable hourly rate for CitiPower's quoted services was the highest point of Impaq's recommended range of labour rates, adjusted to include a 3 per cent profit margin.

Since the AER classified the covering of low voltage mains as a quoted service, it required CitiPower to provide labour costs for this service in its Revised Regulatory Proposal.

19.4.2.3 Changes to service classification

The AER asked CitiPower to provide an hourly labour rate for the audit design service being a service which CitiPower proposed as standard control in its Initial Regulatory Proposal, however the AER classified as a quoted alternative control service in its Draft Determination.[1115]

19.4.2.4 Labour escalation

The AER approved the escalation of quoted services labour rates by the outsourced labour escalation rates it approved for CitiPower's standard control services set out in Appendix K of its Draft Determination.[1116]

[1113] AER, Draft Determination, p891.
[1114] AER, Draft Determination, p891.
[1115] AER, Draft Determination, p864.
[1116] AER, Draft Determination, p892.

19.4.2.5 Price path – quoted services

The AER observed that CitiPower proposed its 2011 labour rate be escalated by the BIS Shrapnel labour escalator, plus CPI over the forthcoming regulatory period.[1117] The AER agreed that it was appropriate to escalate the approved 2011 2 quoted services for years 2012-15, however, it did not consider it appropriate to escalate the labour rate by CPI in addition to the labour escalator. The AER approved escalation of the quoted services labour rates by the outsourced labour rates it approved for CitiPower's standard control services.

19.4.3 CitiPower's Response to AER's Draft Determination

19.4.3.1 CitiPower's proposed labour rates

CitiPower submits that the AER should determine a labour rate for its quoted alternative control services such that CitiPower is permitted to recover its efficient costs of providing those services. CitiPower is not able to recover those costs on the basis of its existing charges or the charges proposed in the AER's Draft Determination.

CitiPower's critique of the labour rate recommended by Impaq in the fee based alternative control services section of this Chapter applies equally to the labour rate for quoted services as for fee based services.

The AER has acknowledged that the actual costs of Victorian DNSPs relative to non-Victorian DNSPs are efficient.[1118] Accordingly, the AER should accept the labour rates for quoted alternative control services proposed in this Revised Regulatory Proposal which will assist CitiPower to recover the efficient costs of providing quoted alternative control services.

CitiPower provides the quoted services set out in the following table.

Quoted Services provided by CitiPower
Covering LV Mains - service cable
Covering LV Mains - all wire cable
Covering LV Mains - scope only
Audit design and construction
Specification and design enquiry
Elective Underground (where overhead service exists)
Recoverable works BH
Damage to overhead service cables caused by high load vehicles – single phase
Damage to overhead service cables caused by high load vehicles – multi phase
High load escort

[1117] AER, Draft Determination, p892.
[1118] AER, Draft Determination, p902.

Table 19.9 Quoted services provided by CitiPower

In this Revised Regulatory Proposal, CitiPower proposes the following labour rates for its quoted services.

Quoted Alternative Control Services	2011 $'s per hour per person (real $2010 ex GST)
General line worker - business hours	$115.14
General line worker - after hours	$126.61
Design/survey - business hours	$123.56
Design/survey - after hours	$139.16
Administration	$47.85

Table 19.10 Labour rates for quoted services provided by CitiPower

As noted above, in its Draft Determination the AER asked CitiPower to provide an hourly labour rate for the audit design service being a service which CitiPower proposed as standard control in its Initial Regulatory Proposal, however the AER classified as a quoted alternative control service in its Draft Determination. CitiPower proposes that the above hourly labour rates for design/survey will apply to this service.

These proposed labour rates for quoted services are also set out in Appendix 9.1 to this Revised Regulatory Proposal.

19.4.3.2 Price path – quoted services

CitiPower observes that the services provided as quoted services consist wholly of labour and materials. CitiPower agrees with the AER's decision that customer prices for materials for quoted services should be set at the cost of the materials to CitiPower.[1119] CitiPower considers that it is appropriate to apply to the labour component of quoted services X factors consistent with the real labour escalator proposed by it in Chapter 8 of this Revised Regulatory Proposal.

The appropriate X factors are set out in the following table.

Description	2012	2013	2014	2015
Quoted Services	(5.0)%	(4.6)%	(4.0)%	(3.6)%

Table 19.11 X factors for quoted services (real)

[1119] AER, Draft Determination, p891.

19.5 Public lighting services

19.5.1 CitiPower's Initial Regulatory Proposal

In Chapter 23 of its Initial Regulatory Proposal, CitiPower described its charging methodology for public lighting services in the next regulatory control period and the application of the control mechanism to public lighting services.[1120]

Section 3.7.8 of the AER's Framework and Approach Paper provides that a price cap form of control will apply to the 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'.*

CitiPower's methodology for developing its charges for public lighting services in the next regulatory control period involves applying the limited building block approach reflected in the AER's public lighting model.

CitiPower 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 adopted input escalation at rates consistent with the standard control services, as set out in its Initial Regulatory Proposal. Additionally a nominal CPI price escalation was applied using the same assumptions as used for standard control services;
- initial labour rates – CitiPower used labour rates consistent with those applied to standard control services;
- real pre-tax WACC – CitiPower used a WACC consistent with that applied to standard control services;
- hours per day - consistent with current award conditions, CitiPower amended the number of hours per day from $8^1/_3$ hours to 8 hours. Consequently, the amount of work completed per day was scaled back by four per cent. This includes:
    - number of bulk lamp changes in 1 day;
    - number of repairs in 1 day;
    - pole inspection rate (per day);
    - number of poles & brackets replaced per day; and
    - number of brackets replaced per day.
- proportion of luminaires that fail between bulk changes - consistent with earlier submissions, the T5-14 light type 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 MAV based on a mass roll out across the whole state.[1121] 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 used a previous quote of $215 ($2010) as a cost input;

[1120] Initial Regulatory Proposal, pp360-67.
[1121] Quotation from the MAV for T5 public lighting 234 to this Revised Regulatory Proposal).

- traffic control costs – CitiPower determined that the traffic control costs were $15.48 ($2010) per light for bulk replacement activities and likely to be higher for fault activities;
- dedicated street lighting poles – cost of pole and bracket – CitiPower determined that the unit costs of these activities were $3,125 ($2010);
- patrol costs – CitiPower observed that costs have been amended to $25 per hour ($2010) to reflect the current contract prices; and
- *existing light prices* – CitiPower provided with its Initial Regulatory Proposal, the public lighting OM&R rates submitted for approval to the AER on 17 November 2009. At the time of submitting its Initial Regulatory Proposal, those rates had not been approved by the AER.

CitiPower proposed a labour rate (normal hours) of $78.12 for 2010 which was derived by taking the AER's approved labour rate of $71.41 in the Public Lighting Decision and applying the wage rate escalators of 4.55 per cent and 5.64 per cent in 2009 and 2010 respectively. These wage rate increases were based on the weighted average of the approved growth rates for the Electrical Trades Union and the Association of Professional Engineers, Scientists and Managers Australia.[1122]

CitiPower proposed a labour rate for night patrols (after hours) which had a 15 per cent loading on the labour rate for normal hours.

CitiPower proposed to continue its current practice of differentiating charges to customers for its public lighting services based on:

- the type of public lighting; and
- the wattage of the lighting.

On 4 March 2010 CitiPower provided the AER with updated information concerning public lighting.

19.5.2 AER's Draft Determination

19.5.2.1 Labour rates

The AER decided that the labour rates which it published in its Public Lighting Decision were fair and reasonable.[1123] Those labour rates were $71.41 per hour for normal hours and $82.12 per hour for after hours work.

The AER engaged Impaq to review the labour costs for all alternative control services and to report on the reasonableness of the Victorian DNSPs proposed hourly labour rates for public lighting services. Impaq recommended the hourly charge out rate for public lighting should be limited to the range of $57 to $74 per hour.[1124]

The AER decided that it was persuaded by Impaq's recommendations. It also gave weight to the rates established in the Public Lighting Decision and calculated a low case and high case labour rate to account for variations in charge out rates between the Victorian DNSPs. It decided to accept labour rates for 2010 of:

- $71.41 per hour for normal hours; and

[1122] Powercor, public lighting model (updated March 2010).
[1123] AER, Draft Determination, p802.
[1124] Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p46.

- $82.12 per hour for after hours (night patrol).

The AER applied the labour cost escalators in its assessment and Draft Determination on labour escalators for standard control services for outsourced labour to the 2010 labour rates in its draft decision on public lighting OMR charges for each year of the regulatory control period.

19.5.2.2 Materials escalators

The AER applied the materials cost escalation for steel to the 2010 unit cost of poles and brackets on non-dedicated poles to derive unit costs for each year of the forthcoming regulatory control period.[1125] However, it did not apply a materials cost escalator for other materials used for public lighting such as the various components with the luminaire (e.g. ballast, photo-electric cells and lamps). This was because it decided that those materials had no comparable material escalator that the AER considered appropriate to apply.

19.5.2.3 Traffic management costs

The AER said that it was of the view that Victorian DNSPs would incur expenditure associated with complying with the *Road Management Act 2004 (Vic)*.[1126] However, the wide disparity in proposed costs suggested that the forecasts may not be reflective of the efficient costs for providing public lighting services.

The AER evaluated the Victorian DNSP's forecast expenditure by comparing the relative size of each DNSP to provide benchmarks for assessment of the expenditure. The AER estimated CitiPower's forecast costs to be approximately four times larger than those of Jemena (who it considered to be the next closest comparable urban DNSP) due to the more stringent requirements for traffic management likely to apply in the CBD due to population and urban density.

19.5.2.4 Geographical information system costs

The AER accepted the Victorian DNSPs proposal of $100,000 in annual Geographical Information System costs.

19.5.2.5 Transitional price smoothing adjustment

The AER accepted CitiPower's proposed transitional adjustment price smoothing factor of 20 per cent in each year of the forthcoming regulatory control period.

19.5.2.6 Failure rates of T5 lights between bulk changes

The AER determined that the failure rate for the percentage of T5 energy efficient lights forecast to fail between bulk changes in the forthcoming regulatory period should be the rate of 11.2 established in its Public Lighting Decision.

19.5.2.7 Proposed costs of poles and brackets

The AER rejected CitiPower's proposed pole and bracket costs of $3,125 on the basis that it was substantially above the cost of $500 taken from the ESCV, *Review of Public Lighting Excluded Service Charges*, Final Decision, August 2004 and adopted by other DNSPs and CitiPower had not provided substantive evince to justify the large cost variance.[1127]

[1125] AER, Draft Determination, p803.
[1126] AER, Draft Determination, p805.
[1127] AER, Draft Determination, p817.

19.5.3 CitiPower's Response to AER's Draft Determination

CitiPower has reviewed all of the matters raised by the AER in its Draft Determination, including where the AER has made adjustments to CitiPower's Initial Regulatory Proposal.

CitiPower has amended its Initial Regulatory Proposal and prepared this Revised Regulatory Proposal to be consistent with the AER's Draft Determination on public lighting, except in respect of the following:

- CitiPower has applied the general materials escalator proposed by it in Chapter 8 of this Revised Regulatory Proposal to materials other than poles and brackets;
- CitiPower has included pole and brackets cost of $1,351.30;
- CitiPower has proposed that 19.5 per cent of T5 (2x14W) lights would fail between bulk changes during the 2011-15 regulatory control period;
- CitiPower has included a cost of $25.43 for patrol vehicles;
- CitiPower has included a cost of $241 for the price of luminaires; and
- CitiPower has included traffic management costs of $13.75 per light.

CitiPower's proposed charges for public lighting services are set out in Appendix 9.1 to this Revised Regulatory Proposal.

19.5.3.1 Materials escalation

As noted above, the AER did not apply a materials cost escalator for materials, other than poles and brackets, used for public lighting such as the various components with the luminaire (eg ballast, photo-electric cells and lamps). This was because it decided that those materials had no comparable material escalator that the AER considered appropriate to apply. This is not a proper basis for the AER to decide not to apply a materials cost escalator to those materials.

CitiPower considers that the AER should apply the general materials escalator proposed by it in Chapter 8 of this Revised Regulatory Proposal to the other materials used for public lighting.

19.5.3.2 Cost of poles and brackets

The AER rejected CitiPower's proposed pole and bracket costs of $3,125 on the basis that it was substantially above the cost of $500 taken from the ESCV, *Review of Public Lighting Excluded Service Charges*, Final Decision, August 2004 and adopted by other DNSPs and CitiPower had not provided substantive evidence to justify the large cost variance.[1128]

CitiPower has further reviewed its proposed pole and bracket costs of $3,125. Upon further review CitiPower observes that the figure appeared to contain labour and other costs not related to pole and bracket costs.

CitiPower notes that there are a range of poles and brackets used across its distribution network. The poles and brackets vary depending on where they are being installed. For example, the kinds of poles used on major and minor roads vary significantly compared to the poles used in residential estates.

[1128] AER, Draft Determination, p817.

Accordingly, in this Revised Regulatory Proposal CitiPower proposes a cost of $1,351.30 for poles and brackets. This cost represents a weighted average of standard poles and brackets used.

In support of its pole and brackets cost, CitiPower provides as an attachment to this Revised Regulatory Proposal quotes from vendors for costs of various poles and brackets from which CitiPower derived a weighted average.[1129]

Accordingly, CitiPower submits that the AER should approve its revised cost of $1,351.30 for poles and brackets in its Final Determination.

19.5.3.3 Failure rates of T5 lights between bulk changes

In its public lighting model, CitiPower proposed that 19.5 per cent of T5 (2x14W) lights would fail between bulk changes during the 2011-15 regulatory control period. As noted above the AER determined that the failure rate should be 11.2 per cent as established in its Public Lighting Decision.

The AER approved the rate of 19.5 per cent for CitiPower in CitiPower's 2010 proposed tariffs for distribution, transmission and unmetered supplies for the period 1 January to 31 December 2010. These rates were apparent from CitiPower's model provided to the AER and in the AER's updated version of the model provided to CitiPower by email on 26 November 2009 in respect of the tariff approval. The AER approved CitiPower's tariffs on 14 December 2009. Attached to this Revised Regulatory Proposal is a copy of the AER's letter approving CitiPower's 2010 prices for alternative control services.[1130]

Accordingly, CitiPower submits that the AER should approve its failure rate of 19.5 per cent for T5 (2x14W) lights in its Final Determination.

19.5.3.4 Patrol vehicle costs

In the AER's model to determine the prices for public lighting for the purposes of the Draft Determination, the AER has used a rate of $10 for patrol vehicle costs (per hour).[1131] In its Public Lighting Decision, the AER had observed that:[1132] '*CitiPower and Powercor also provided quotes for patrol vehicle costs, and proposed that these be amended from the $10 used in 2004 cost model to $25. No other distributors submitted increased patrol vehicle costs in their submissions'*.

CitiPower submits that the rate for patrol vehicles should be $25.43 per hour. This is the average of the rates quoted in CitiPower's internal patrol rates document, which sets out the rates for external contractors in the regional areas. As a reasonableness check based on the ATO 'rate per business kilometre' for an ordinary engine 1.601–2.6 litre (1,601–2,600cc) of 74 cents per kilometre[1133] multiplied by an approximated 40 kilometre per hour travelled by the patrol vehicle, the rate is $29.60 per hour.

The AER should accept CitiPower's proposed rate in its Draft Determination because it is based on a current external rate. The fact that other distributors did not submit increased patrol vehicle costs in their submissions to the AER in respect of its Public Lighting Decision gives no basis for the AER to reject CitiPower's proposed cost.

[1129] Attachment 230 to this Revised Regulatory Proposal.
[1130] Attachment 232 to this Revised Regulatory Proposal.
[1131] This is apparent from the input area of the Public Lighting Cost Build up Model under the sub heading 'Inputs – all lamps'.
[1132] AER, Public Lighting Decision, p38.
[1133] ATO, Tax Return Information on Work-related Car Expenses (Attachment 238 to this Revised Regulatory Proposal).

19.5.3.5 Cost of luminaires

In the AER's model to determine the prices for public lighting for the purposes of the Draft Determination, the AER has used a unit cost of $193 for luminaires.[1134] The value of $193 came from a quote provided by the MAV. The MAV requested a quote for the bulk replacement of lamps across Victoria. This quote was for 10,000 luminaire and therefore included a volume discount.

CitiPower completes ad hoc maintenance on luminaires on an as required basis. Accordingly, it does not receive a volume discount from its vendors. In its Initial Regulatory Proposal, CitiPower proposed a cost of $215 per luminaire based on an ordering quantity of 100. This cost was based on a quote obtained in 2008. CitiPower has recently obtained a new quote for 100 luminaires from Pierlite Australia Pty Ltd. The quote shows a cost of $241 per luminaire.[1135]

CitiPower has used this cost in determining its public lighting costs in this Revised Regulatory Proposal. As this is a recent quote and is not based on a bulk discount, this quote gives a better indication of the cost of luminaires than the quote provided by MAV used by the AER in its Draft Determination. Accordingly, CitiPower considers that the AER should use this cost of $241 for the price of luminaires in its Final Determination.

19.5.3.6 Traffic Management Costs

The AER determined benchmarks for traffic management costs based on the AER's evaluation of CitiPower's 'equivalent' DNSP.

CitiPower has reviewed its traffic management costs and has revised its proposed traffic management costs to $13.75 per light.

CitiPower submits that its proposed traffic management costs should be accepted by the AER. The works are tendered through an public tender process, which results in efficient costs.

19.5.3.7 Price path – public lighting

In its Draft Determination and the Framework and Approach Paper, the AER said that a CPI-X approach would be used to establish a price path for alternative control services.[1136] CitiPower considers that it is appropriate to apply to the unit rates of public lighting services X factors consistent with the escalators proposed by it in Chapter 8 of this Revised Regulatory Proposal.

The appropriate X factors are set out in the following Table 19.12.

Description	2012	2013	2014	2015
Public Lighting	(0.9)%	2.3%	1.4%	1.5%

Table 19.12 X factors for public lighting (real)

[1134] This is apparent from the 'Unit cost – luminaire' section of the AER's model under the 'Energy Efficient Lighting' subheading.
[1135] Quotation from Pierlite Australia Pty Ltd for cost of luminaires dated 24 June 2010 (Attachment 233 to this Revised Regulatory Proposal).
[1136] AER, Framework and Approach Paper, p79.

19.6 CitiPower's Revised Regulatory Proposal

CitiPower has revised its Initial Regulatory Proposal and prepared this Revised Regulatory Proposal to propose charges for fee based alternative control services that are designed to assist its recovery of its efficient costs of providing those services. In addition, CitiPower proposes a labour rate for quote based alternative control services that is designed to assist its recovery of its efficient costs of providing those services.

CitiPower's proposed charges for fee based alternative control services and its labour rate for quoted alternative control services are provided in Appendix 9.1 to this Revised Regulatory Proposal.

CitiPower has revised its Initial Regulatory Proposal and prepared this Revised Regulatory Proposal to be consistent with the AER's Draft Determination on public lighting, except in respect of the following:

- CitiPower has applied the general materials escalator proposed by it in Chapter 8 of this Revised Regulatory Proposal to materials other than poles and brackets;
- CitiPower has included pole and brackets cost of $1,351.30;
- CitiPower has proposed that 19.5 per cent of T5 (2x14W) lights would fail between bulk changes during the 2011-15 regulatory control period;
- CitiPower has included a cost of $25.43 for patrol vehicles;
- CitiPower has included a cost of $241 for the price of luminaires; and
- CitiPower has included traffic management costs of $13.75 per light.

CitiPower's proposed charges for public lighting services are provided in Appendix 9.1 to this Revised Regulatory Proposal.

Appendix 1.1 - Key Assumptions Underlying Capex and Opex Forecasts in CitiPower's Revised Regulatory Proposal

This Appendix sets out the key assumptions which underlie:

- the proposed capex forecast as set out and included in CitiPower's building block proposal; and
- the proposed opex forecast as set out and included in CitiPower's building block proposal.

Assumptions common to capex and opex forecasts

The following are the key assumptions common to the capex and opex forecasts in the Revised Regulatory Proposal:

1. **Forecasts of spatial peak demand:** spatial peak demand in the 2011-15 regulatory control period will be as set out in Revised Regulatory Template 6.3.
2. **Regulatory change:** The regulatory obligations and arrangements currently applicable to CitiPower will continue to apply in their current form throughout the 2011-15 regulatory control period. Any changes that do occur during the next regulatory control period may be the subject of a cost pass through.
3. **Forecasts of customer numbers:** Customer growth over the 2011-15 regulatory control period will be as set out in Revised Regulatory Template 6.3.
4. **Labour cost escalator:** Real wage growth for CitiPower in the 2011-15 regulatory control period will be as reflected in the labour cost escalators set out in Chapter 8 of the Revised Regulatory Proposal.
5. **Contracts/other cost escalator:** Real contracts/other cost growth for CitiPower in the 2011-15 regulatory control period will be as reflected in the contract and other cost escalator set out in Chapter 8 of the Revised Regulatory Proposal.
6. **Materials cost escalators:** The real growth in the cost of materials over the 2011-15 regulatory control period will be as reflected in the material cost escalators set out in Chapter 8 of the Revised Regulatory Proposal.
7. **Forecast inflation:** 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.
8. **Unit rates applied to key items of plant and equipment for both labour and material unit rates:** The 2009 unit rates incurred by CitiPower and reflected in 2009 average costs of works 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.

9. **2010 indexation:** 2009 dollars are related to 2010 dollars by CPI consistent with the CPI value in the Revised Regulatory Templates.

Assumptions specific to capex forecasts

The following are the key assumptions specific to the capex forecasts in the Revised Regulatory Proposal:

1. **CitiPower's internal documents:** CitiPower's 'Network Augmentation Planning Policy and Guidelines' and asset management documents will apply in their current form throughout the 2011-15 regulatory control period. This assumption relates to reinforcement and reliability and quality maintained capex.

2. **CitiPower's internal documents are efficient and prudent**: In order to satisfy the capex objectives, 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'. 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 capex.

3. **Expenditure on new customer connections**: CitiPower's base year gross capex on new customer connections, determined as outlined in Chapter 9 of the Revised Regulatory Proposal, reflects the capex that would have been incurred by an efficient and prudent operator to satisfy the capex objectives. This assumption relates to new customer connections capex.

4. **New customer capital contributions:** In each year of the 2011-15 regulatory control period, the ratio of customer contributions received to new customer connections expenditure will be that ratio realised in 2009 after adjusting the customer contributions received in 2009 for the forecast impact of 'The AER's Conclusion on the Benchmark Upstream Augmentation Charge Rates for CitiPower's Network', 25 June 2010 and the P_0, X factor and WACC values included in this Revised Regulatory Proposal (as outlined in Chapter 9). This assumption relates to new customer connections capex.

Assumptions specific to opex forecasts

The following are the key assumptions specific to the opex forecasts in the Revised Regulatory Proposal:

1. **Recurrent 2009 expenditure:** CitiPower's 2009 recurrent opex reflects the opex that would have been incurred by an efficient and prudent operator in order to satisfy the opex objectives.

2. **Step change:** CitiPower's proposed step changes will occur and the effect on CitiPower's opex in the 2011-15 regulatory control period relative to its 2009 opex will be as forecast by CitiPower.

3. **CitiPower's policies, strategies and procedures:** CitiPower's policies, strategies and procedures set out in Revised Regulatory Template 6.4 will continue to apply in their current form throughout the 2011-15 regulatory control period.

4. **Scale escalation:** The effect of network growth and customer growth on CitiPower's 2011-15 opex will be as forecast by the application of the scale escalators, set out in Chapter 7 of the Revised Regulatory Proposal, to 2009 opex.

Appendix 1.2 - Certification

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:

____

dated this 16th day of July 2010

Peter Tulloch
CHAIRPERSON

Appendix 1.3 - Statutory Declaration

NATIONAL ELECTRICITY (VICTORIA) LAW
SECTION 28M(d)
STATUTORY DECLARATION

I, Shane. Augustus Breheny (*full name*)

of 40 Market Street Melbourne. (*address*)

being an officer, for the purposes of the *Corporations Act 2001* (Cth), of CitiPower Pty ('**CitiPower**'), do solemnly and sincerely declare that the response of CitiPower to the Australian Energy Regulator's regulatory information notice ('**Notice**') dated 4 June 2010:

1. is true and accurate;

2. in accordance with the requirements of the Notice; and

3. in all material respects can be relied upon by the AER to assess the regulatory proposal or the revised regulatory proposal as the case may be 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 40 Market St in the State of Victoria

this 19th day of July 2010

SABreheny (*Signature of person making declaration*)

Before me: ________________ (*Signature of authorised witness*)

(The witness must print their name, address and their authority under section 107A of the *Evidence Act 1958* (Vic) to witness a statutory declaration).

Kaye-Frances Rands
40 Market Street, Melbourne 3000
An Australian Legal Practitioner within the meaning of the Legal Profession Act 2004

Appendix 1.4 -Index to attachments to Revised Regulatory Proposal

The following is an index to the attachments to the Revised Regulatory Proposal. CitiPower has not included in this index nor attached to this Revised Regulatory Proposal the AER's Draft Determination or the expert reports, models and other materials prepared or commissioned by the AER and provided to CitiPower in connection with the Draft Determination (**AER Draft Determination Documents**) because these documents are already in the AER's possession. However, CitiPower should be taken to have submitted to the AER with this Revised Regulatory Proposal all AER Draft Determination Documents.

ID	Document name	Revised Regulatory Proposal reference	Confidential
1	CitiPower AER Regulatory Information Notice Under Division 4 of Part 3 (Revised Regulatory Templates)		Yes
2	CitiPower Post Tax Revenue Model		Yes
3	CitiPower Roll Forward Model		Yes
4	CitiPower Public Lighting Model		Yes
5	CitiPower EBSS Model		Yes
6	CitiPower S Factor True Up Model		Yes
7	CitiPower Customer Capex Model	9	Yes
8	CitiPower Customer Contribution Rate Model	9	Yes
9	CitiPower Cost Escalation Model	7	Yes
10	CitiPower Cost Forecast Model	6	Yes
11	CitiPower Linked 2009-15 RIN Cost Templates		Yes
12	CitiPower GSL Model	6	Yes
13	CitiPower Superannuation Step Change Model	6	Yes
14	CitiPower Changes to RIN Templates		Yes
15	CitiPower RIN Allocators		Yes
16	CitiPower Justification for no RIN Template Information		Yes
17	CitiPower Regulatory Account Adjustments		Yes

ID	Document name	Revised Regulatory Proposal reference	Confidential
18	CitiPower Worked Example of Pass-through Factor Model	3	Yes
19	CitiPower Cost build up model for Alternative Control Services	19	Yes
20	Australian Government Solicitor, Letter of advice to Mr Tom Motherwell, Department of Industry Tourism and Resources titled 'Assessment of expenditure forecasts', 10 October 2006.	1	No
21	AER, South Australian Draft Determination	1, 3, 5, 6, 7	No
22	AER, South Australian Final Determination	1, 3, 7, 8, 17	No
23	AER, South Australian Framework and Approach Paper	1, 3	No
24	AER, Queensland Final Determination	1, 3, 17	No
25	AER, Queensland Framework and Approach Paper	1, 3	No
26	AEMC staff observations – cost recovery by DNSPs for connection services and definition of prescribed connection services, 21 June 2010.	3	No
27	UED, Rule change proposal: Amendment to the distribution pricing proposal provisions of the National Electricity Rules to provide for the explicit inclusion of transmission-related and other relevant charges in a distribution network service provider's pricing proposal, 22 June 2010.	3	No
28	AEMC, National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010 No. 7.	3	No
29	AEMC, Rule Determination, National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010, 1 July 2010.	3	No
30	ESCV, Guideline 15	2, 3	No
31	ESCV, 2006-10 EDPR, Volume 1, Final Decision	1, 4, A6.1, 14	No
32	ESCV, 2006-10 EDPR, Volume 2, Price Determination	3, 17	No
33	Email from the AER (Craig Madden) to the Victorian DNSPs entitled 'AER advice - Recovery of avoided TUOS payments', 29 June 2010	3	No
34	NIEIR, Electricity sales and customer numbers for the CitiPower region to 2019, June 2010	4	No
35	Frontier, letter re NIEIR's methodology overview, 10 May 2010	4	No
36	Frontier, Review of policy adjustments, July 2010	4	No
37	Frontier, Review of ACIL Tasman recommendations, June 2010	4	No
38	MCE, Money Isn't All You're Saving, Australia's standby power strategy 2002-2012, 2002	4	No

ID	Document name	Revised Regulatory Proposal reference	Confidential
39	Equipment Energy Efficiency Program, Achievements 2008/09, December 2009	4	No
40	Department of the Environment, Water, Heritage and the Arts, Consultation Regulation Impact Statement: National Legislation for Appliance and Equipment Minimum Energy Performance Standards (MEPS) and Energy Labelling, January 2010	4	No
41	Faruqui, A and Sergici, S (Brattle Group), Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence, 10 January 2009	4	No
42	Charles River Associates, Impact Evaluation of the California Statewide Pricing Pilot, 16 March 2005	4	No
43	NIEIR, Maximum summer demand forecasts for CitiPower to 2020, June 2010	4	No
44	Minister for Energy and Resources, Letter re Deferral of Network Time of Use Tariffs, 24 February 2010	4	No
45	CitiPower and Powercor Australia, presentation to AMI retailers forum, Network Tariffs, Considered tariffs for 2011-15 price review period, 13 July 2010	4	No
46	AGL Sales – Standing Offer – Tariffs applicable 1 January 2010	4	No
47	Origin Energy – Standing Offer – Tariffs applicable 1 January 2010	4	No
48	CitiPower, Templates 10(a) to 10(g) submitted to the ESCV in the 2006-10 EDPR process, 13 November 2004	4	No
49	ESCV, Electricity Price Review 2006-10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final decision Volume 1, Statement of Purpose and Reasons, October 2006	4	No
50	SKM, CitiPower/Powercor Demand Forecasts, 8 July 2010	4	No
51	Curriculum vitae of Cheng Lee, SKM	4	No
52	Curriculum vitae of Keith Frearson, SKM	4	No
53	Oakley Greenwood, Review of AMI Benefits and Consolidation of AMI Costs and Benefits (Draft Report), May 2010	4	Yes
54	Minister Assisting the Minister for Climate Change and Energy Efficiency, Media release re Home Insulation Safety Plan, 1 April 2010	4	No
55	DPI, Presentation to the AMI Policy Committee, 29 June 2010	4	Yes
56	Additional evidentiary material regarding policies underpinning policy adjustments to energy consumption and maximum demand forecasts	4	No

ID	Document name	Revised Regulatory Proposal reference	Confidential
57	Hawke, A, Hawke Report, Review of the Administration of the Home Insulation Program, 6 April 2010	4	No
58	'What is Google PowerMeter' (webpage), available at http://www.google.com/powermeter/about/about.html	4	No
59	'Become a Google PowerMeter partner' (webpage), available at http://www.google.com/powermeter/about/partnerships.html	4	No
60	CurrentCost, CC128 ENVI Manual available at www.currentcost.com	4	No
61	Australian Bureau of Agriculture and Resource Economics Australian Energy Statistics, Table f: Australian energy consumption by industry and fuel type - energy unit and Table i: Australian consumption of electricity by state, 2009 (available at http://www.abareconomics.com/publications_html/data/data/data.html#engHIST) retrieved 16 July 2010	4	No
62	Energy Efficient Strategies, Energy use in the Australian residential sector 1986-2020, prepared for Department of the Environment, Water, Heritage and the Arts, May 2008 (available at http://www.energyrating.gov.au/library/pubs/2008-energy-use-aust-res-sector-full.pdf), retrieved 16 July 2010	4	No
63	Equipment Energy Efficiency Committee Department, Lighting RIS	4	No
64	Insulation Council of Australia and New Zealand, Submission to Senate Standing Committee on Environment, Communications and the Arts, Inquiry into the Energy Efficient Homes Package, 18 December 2009	4	No
65	Sustainability First and Engage Consulting Limited, International Smart Meter Trials: Selected Case Studies Smart Tariffs and Customer Stimuli, May 2008	4	No
66	Alan Pears, Residential sector energy efficiency scenario, Background, Framework and Rationales, February 2007	4	No
67	Mark Ellis & Associates, RIS: MEPS alternative strategies for Linear Fluorescent Lamps, prepared for Australian Greenhouse Office, December 2003	4	No
68	Country Energy, The Country Energy Home Energy Efficiency Trial, June 2006	4	No
69	George Wilkenfeld and Associates with Energy Efficient Strategies, Options to reduce greenhouse emissions from new homes in Victoria through the building approval process, prepared for Department of Sustainability and Environment, April 2007	4	No
70	ACIL Tasman, Victorian Electricity Price Review, Review of electricity sales and customer numbers forecasts, Final report, prepared for the AER, 21 April 2010	4	No

ID	Document name	Revised Regulatory Proposal reference	Confidential
71	ACIL Tasman, The impact of an ETS on the Energy Supply Industry, prepared for Energy Supply Association of Australia, 23 July 2008	4	No
72	Energy Efficient Strategies, Regulatory Impact Statement Consultation Draft, Revision to the labelling of algorithms and revised MEPS levels and other requirements for air conditioners, prepared for Department of the Environment, Water, Heritage and the Arts, September 2008	4	No
73	AER , State of the Energy Market 2009, December 2008	4	No
74	Brattle Group, Lessons from Demand Response: Trials and Potential Savings for the EU, 3-4 March 2010	4	No
75	Charles River Associates International and Impaq Consulting, Advanced Interval Meter Communications Study – Draft Report prepared for the Department of Infrastructure, December 2005	4	No
76	DECC, Impact assessment of a GB-wide smart meter roll out for the domestic sector, May 2009	4	No
77	Electric Power Research Institute, The role of dynamic pricing in fostering the efficient use electric sector resources, 25 March 2008	4	No
78	ESCV, Installing interval meters for electricity customers - costs and benefits, position paper, November 2002	4	No
79	ESCV, Mandatory rollout of interval meters for electricity companies, Draft decision, March 2004	4	No
80	Energy Efficient Strategies, Standby Power - Current Status, prepared for the Equipment Energy Efficiency Committee, October 2006	4	No
81	Frontier, Impacts of climate change policies on electricity retails, prepared for the AEMC, June 2009	4	No
82	Maunsell AECOM Australia Pty Ltd, Climate change impact assessment on CitiPower EDPR 2011-2015 (draft), 1 July 2009	4	No
83	McLennan Magasanic Associates, Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets prepared for the Federal Treasury, 11 December 2008	4	No
84	NERA, Cost Benefit Analysis of Smart Metering and Direct Load Control - Work stream 4: Consumer Impacts, Phase 2 consultation report, prepared for the MCE, 29 February 2008	4	No
85	Owen, G and Ward, J (Sustainability First), Smart Meters: Commercial, policy and regulatory drivers, March 2006	4	No
86	Owen, G and Ward, J (Sustainability First), Smart Meters: Commercial, policy and regulatory drivers, March 2006 (Appendices)	4	No
87	Owen, G and Ward, J (Sustainability First), Smart Tariffs and household	4	No

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88	DPI, Advanced Metering Infrastructure, Home Area Network functionality Guideline, Version 0.5, 20 November 2008	4	No
89	ESCV, ESC information session, Victorian Energy Efficiency Target, 26 March 2010	4	No
90	Carbon Trust, Advanced metering for SMEs, Carbon and cost savings, full report, 2007	4	No
91	Hydro One Brampton Networks Inc., Conservation and demand management plan, Annual Report to December 31 2005, 31 March 2006	4	No
92	Total Environment Centre Inc., Submission - Cost benefit analysis of options for a national smart meter roll-out (phase two) Regulatory Impact Statement, May 2008	4	No
93	EMET Consultants Pty Ltd, Energy Efficiency improvement in the Residential Sector, prepared for Sustainable Energy Authority of Victoria, April 2004	4	No
94	Frontier, Smart Metering, prepared for Centrica, October 2007	4	No
95	Commonwealth Government, Australia's Low Pollution Future, the Economics of Climate Change Mitigation, 2008	4	No
96	Application by Optus Mobile Pty Limited and Optus Networks Pty Limited [2006] ACompT 8	5	No
97	Application by Energy Australia and Others [2009] ACompT 8	1, 5, A6.1, 12, 17	No
98	NERA, Allen Consulting Group's Review of NERA's Benchmarking of Contractors' Margins Critique, October 2007	5	No
99	ESCV, GAAR, Chapter 5	5	No
100	ESCV, Electricity Distribution Price Review 2006-10 Final Decision: Notice of Errata, 23 November 2005	5	No
101	ESCV, Draft GAAR, Chapter 5	5	No
102	NERA, Review of Operating Expenditure Efficiency, July 2010	1, 5	No
103	SKM, Market Price Survey #4 Results of Survey for CitiPower Distribution Equipment / Materials, Capex and Opex Activities of Work, 6 July 2010	1, 5	No
104	AER, Jemena Gas Access Final Decision	1, 5, 8	No

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107	SMS Consulting, Review of CHED Services' forecast for FRC systems support, 25 February 2009 (Attachment F.11 to ETSA Utilities Revised Regulatory Proposal 2010-2015 dated 14 January 2010)	5, 9	Yes
108	Powercor Network Services Pty Ltd ABN 94 123 230 240, Financial Statements for the year ended 31 December 2009 (Previously provided to AER under cover of email from B Cleeve, Manager Price Review, CitiPower and Powercor Australia, to S Sandles, AER, dated 29 March 2010)	5	Yes
109	AEMC, Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18, 16 November 2008	5, 6, 9, 17	No
110	SCO, Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution Explanatory Material, April 2007	5, 17	No
111	Extract of CitiPower Board Minutes, 24 August 2004	5	Yes
112	Extract of Powercor Australia Board Minutes, 24 August 2004	5	Yes
113	Extract of CitiPower Executive Committee Minutes, 10 December 2004	5	Yes
114	Extract of Powercor Australia Executive Committee Minutes, 10 December 2004	5	Yes
115	Presentation given by Shane Breheny, Chief Executive Officer CitiPower and Powercor Australia, and Julie Williams, Chief Financial Officer CitiPower and Powercor Australia, to Executive Committees of CitiPower and Powercor Australia at meeting of 10 December 2004	5	Yes
116	Extract of CitiPower Executive Committee Minutes, 27 January 2005	5	Yes
117	Extract of Powercor Australia Executive Committee Minutes, 27 January 2005	5	Yes
118	CitiPower Board Paper, Related Party Contract Recommendations, 17 November 2006	5	Yes
119	Powercor Australia Board Paper, Related Party Contract	5	Yes

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120	Letter from M Sturgess, General Manager, PNS to R Gross, General Manager Regulation, CitiPower and Powercor, 'Request for Information on Allocation of PNS 2009 Expenditure', 26 March 2010 (Previously provided to AER under cover of email from B Cleeve, Manager Price Review, CitiPower and Powercor Australia, to S Sandles, AER, dated 29 March 2010)	5	Yes
121	Powercor Australia, Regulatory Accounts, 31 December 2009 (Previously provided to the AER in soft copy under cover of an email from R Gross, General Manager Regulation, CitiPower and Powercor to C Pattas, General Manager Network Regulation South Branch, AER dated 30 April 2010 and in hard copy under cover of a letter of the same date from R Gross to C Pattas)	5	Yes
122	CitiPower, Regulatory Accounts for the Year Ended 31 December 2009 (Previously provided to the AER in soft copy under cover of an email from R Gross, General Manager Regulation, CitiPower and Powercor to C Pattas, General Manager Network Regulation South Branch, AER dated 30 April 2010 and in hard copy under cover of a letter of the same date from R Gross to C Pattas)	5	Yes
123	Letter from D Scott, Mercer, to T Mutton, CitiPower and Powercor, dated 28 June 2010 regarding projected superannuation expense under AASB 119	6	No
124	Letter from D Scott, Mercer, to T Mutton, CitiPower and Powercor, dated 28 June 2010 regarding interim AASB 119 results – six months ending 30 June 2010	6	No
125	ESCV, Final Decision, Electricity Distributors' Communications in Extreme Supply Events, December 2009	6	No
126	ESCV, Final Amendments to the Electricity Distribution Code and the Energy Retail Code, 24 February 2010	6	No
127	ESCV, Distribution Code	6, 9	No
128	Cost build up model for communications in extreme supply events	6	No
129	CitiPower's 2009 Distribution Licence Fee Invoice	6	No
130	Cost build up model for Outcomes Monitoring and Compliance step change	6	No
131	Australian Government, Fact Sheet Superannuation – Increasing the Superannuation Guarantee Rate to 12 per cent	6, 13	No

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132	Australian Government, webpage entitled 'Banking the benefits of the boom with fairer concessions for Super' accessed on 12 July 2010	6	No
133	SKM Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010	7	No
134	PB, Letter re Application of network growth escalators for opex forecasts, 2 July 2010	7	No
135	PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015, November 2009	7, 9	No
136	PB, Review of ETSA Utilities' revised regulatory proposal for the period July 2010 to June 2015, May 2010	7	No
137	ETSA, Revised Regulatory Proposal 2010-2015, 14 January 2010	4, 7	No
138	SKM, Impact of ageing assets on CitiPower operating costs, 8 July 2010	7, 9	No
139	Curriculum vitae of Ben Kearney, SKM	7	No
140	Curriculum vitae of Cliff Jones, SKM	7	No
141	AER, NSW Final Determination	8, 17	No
142	AER, NSW Draft Determination	8	No
143	KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010	8	No
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145	Energy Futures Australia, Advanced Metering for energy supply in Australia, prepared for Total Environment Centre, final revised version, 17 July 2007	4	No
146	Econtech, Labour cost growth forecasts 2007/08 to 2016/17, 19 September 2008	8	No
147	AER, Draft Decision, SP AusNet transmission determination 2008-09 to 2013-14, 31 August 2007	8	No
148	AER, Final decision, SP AusNet transmission determination 2008-09 to 2013-14, January 2008	8	No
149	Email from ABS to DLA Phillips Fox re LPI dated 8 July 2010	8	No
150	Email from ABS to DLA Phillips Fox re AWE dated 8 July 2010	8	No
151	ABS 6302.0 Average Weekly Earnings, Australia, February 2010 available at www.abs.gov.au, accessed 8 July 2010.	8	No

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153	ABS, 1292.0, Australian and New Zealand Standard Industrial Classification (ANZSIC), 1993	8	No
154	ABS, Labour Statistics: Concepts, Sources and Methods, April 2007	8	No
155	SKM, Victorian Distribution Network Service Providers cost escalator updates, Final Report – CitiPower and Powercor Asset Categories, 8 July 2010	8	No
156	KPMG, Assessment of the AER's Draft Decision on Labour Cost Escalation: Victoria 13 July 2010	8	No
157	CitiPower, SCADA and network control capex material projects templates	9	No
158	AER, Queensland Draft Determination, Appendices	9	No
159	PB, Review of ENERGEX regulatory proposal for the period July 2010 to June 2015, 2009	9	No
160	SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010	9	No
161	CitiPower, Reinforcement capex material projects templates	9	No
162	PwC, Methodology for the calculation of debt risk premium, 19 July 2010	1, 12	No
163	EA Technology Consulting, Commentary on Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15 (Draft Decision) June 2010, July 2010	9	No
164	CitiPower, Reliability and quality maintained capex material programs templates	9	No
165	SP AusNet, Communication re forecast 66kV and 22kV primary plan replacement works, 14 September 2009	9	No
166	High Voltage Protection Sub-Code, July 2008	9	No
167	ORG, Electricity System Code, October 2000	9	No
168	CitiPower, Minutes to the Capital Investment Committee meeting ('State of the Network' presentation), 1 June 2010	9	Yes
169	AER, Draft Decision, Benchmark Upstream Augmentation Charge Rates for CitiPower's Network, 19 February 2010	9	No
170	AER, Guidance Paper, The AER's Conclusion on the Benchmark Upstream Augmentation Charge Rates for CitiPower's Network, 25 June 2010	9	No
171	PB, Repex Model Review, July 2010	9	No
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173	IT service provider information	9	No
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176	CEG, Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates, A report for Victorian Electricity DBs, July 2010	1, 12	No
177	Value Adviser Associates, Market Risk Premium: Comments on AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010	12	No
178	International Monetary Fund, IMF Working Paper, Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis, May 2010	12	No
179	Application by Telstra Corporation Limited [2010] ACompT 1	12	No
180	ACCC, ULLS Final Decision, Chapter B.7 of Appendix B (Cost of capital)	13	No
181	Monkhouse P (1993), 'The cost of equity under the Australian dividend imputation tax system', Accounting and Finance, volume 33	13	No
182	Peter Feros, Review of WACC parameters: Gamma, ETSA Price Reset, 22 June 2009	13	No
183	N. Hathaway and B. Officer, The Value of Imputation Tax Credits – Update 2004, Capital Research Pty Ltd, November 2004	13	No
184	NERA, Payout ratio of regulated firms, report for Gilbert and Tobin, 5 January 2010	13	No
185	Robert R. Officer, Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers, 23 June 2009	13	No
186	John C Handley and Krishnan Maheswaran, 'A measure of the efficacy of the Australian imputation tax system', The Economic Record, volume 84, number 264, March 2008	13	No
187	SFG, Response to the AER draft determination in relation to gamma, 13 January 2010	13	No
188	Christopher L Skeels, A Review of the SFG Dividend Drop-Off Study – A Report prepared for Gilbert and Tobin, 28 August 2009	13	No
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190	Neville Hathaway, Comment on: "A Measure of the Efficacy of the Australian Imputation Tax System" by John Handley and Krishan Maheswaran, July 2010	13	No
191	Christopher L Skeels, Response to AER Questions, 21 September 2009	13	No
192	SFG, Issues relating to the estimation of gamma, 15 July 2010	13	No
193	Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6		No
194	Australian Government Fact Sheet, Cutting the Company Tax Rate (accessed 8 July 2010)	13	No
195	Media release by Prime Minister entitled 'Breakthrough agreement with industry on improvements to resources taxation', 2 July 2010, http://www.pm.gov.au/node/6868	13	No
196	Neville Hathaway, Accessing the ATO statistics on the ATO website, July 2010	13	No
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198	R Officer, 'The cost of capital of a company under an imputation tax system' (1994) Accounting and Finance 1	13	No
199	D Beggs and C Skeels, 'Market Arbitrage of Cash Dividends and Franking Credits' The (2006) 82 (258) Economic Record 239	13	No
200	J Handley, Further Comments on the Valuation of Imputation Credits, 15 April 2009	13	No
201	SFG Consulting, The impact of franking credits on the cost of capital of Australian firms, 16 September 2008	13	No
202	Christopher L Skeels, Estimation of γ, 25 June 2009	13	No
203	SFG Consulting, The value of imputation credits as implied by the methodology of Beggs and Skeels (2006), 1 February 2009	13	No
204	NERA, AER's Proposed WACC Statement—Gamma: A report for the Joint Industry Associations, 30 January 2009	13	No
205	J Handley, Memorandum to AER: Advice on Gamma in Relation to the 2010-2015 Qld/SA Electricity Distribution Determinations, 20 October 2009	13	No

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207	J Field, Reliability of data used in dividend drop-off study, 5 January 2010	13	No
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209	M Dempsey and G Partington 'Cost of Capital equations under the Australian imputation credit system' (2008) 48(3) Accounting and Finance 445	13	No
210	D Bellamy and S Gray, Using stock Price Changes to Estimate the Value of Dividend Franking Credits (2004) Working Paper, University of Queensland Business School	13	No
211	D Cannavan, F Finn and S Gray, 'The Value of Dividend Imputation Tax Credits in Australia' (2004) 74 Journal of Financial Economics 167	13	No
212	SFG Consulting, Further analysis in response to AER Draft Determination in relation to gamma, 4 February 2010	13	No
213	ORG, 2001-05 EDPR, Volume 1, chapter 5 (Efficiency carryover)	14	No
214	ORG Appeal Panel Decision	14	No
215	AER, EBSS Guideline	14, 15	No
216	AER, EBSS Final Decision	14, 15	No
217	Letter from B Cleeve, Manager Price Review, CitiPower and Powercor Australia to B Burkitt, Director Network Regulation, AER entitled 'Regulatory accounts, provisions and AMI adjustment to regulatory accounts' 3 February 2010	6, 14	No
218	Letter from T Imbesi, Partner, Deloitte, to J Williams, Chief Financial Officer, CHEDHA, titled 'CitiPower Regulatory Accounts: Accounting treatment of provisions', 20 July 2010	6, 14	Yes
219	D.C. Pearce, Statutory Interpretation in Australia, 6th edition, 2006, Chapter 10	14	No
220	AER, ACT Final Determination	17	No
221	Independent Pricing and Regulatory Tribunal, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination	17	No
222	Queensland Competition Authority, Final Determination on the Regulation of Electricity Distribution 2005-10	17	No

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223	ESCV, Credit Support Arrangements, Final Decision, October 2006	17	No
224	Allen Consulting Group, 'Retailer DuOS Credit Support Arrangements Implementation Issues in Victoria, Report to Essential Services Commission, June 2006	17	No
225	Letter from R Hermann (CitiPower/Powercor Australia) to ESCV in respect of ESC Credit decision, 18 August 2006	17	No
226	Default Use of Systems Agreement	17	No
227	Impaq, Review of Distributors Proposed Rates in ACS Charges dated 2 June 2010, reference – 'impaq final report – cp and pc confidential version (D2010-03621655).DOC'	5, 19	Yes
228	Source spreadsheets for Powercor Australia's travel times (three worksheets for 2005, 2006 and 2007)	19	No
229	Norfolk, Financial Results for the Year Ended 31 March 2010, presentation dated 26 May 2010, p15	19	No
230	Quotations from vendors for the costs of poles and brackets	19	Yes
231	CHED Services Contract with AMRS for the Supply of Cyclic Field and Special Meter Reading Services	19	Yes
232	Letter from AER approving CitiPower's 2010 prices for alternative control services,14 December 2009	19	No
233	Quotation from Pierlite Australia Pty Ltd for cost of luminaires dated 24 June 2010	19	Yes
234	Quotation from the Municipal Association of Victoria for T5 public lighting	19	Yes
235	Hays' salary survey 2009, Sector Commentary, Manufactoring & Ops, p118	19	No
236	ETSA, Network Tariff & Negotiated Services, June 2010	19	No
237	Hays, Hays Salary Guide 2010	19	No
238	ATO, Tax Return Information on Work-related Car Expenses (website accessed on 12 July 2010)	19	No
239	Servicestream, Presentation - Working Together CitiPower/Powercor Contract Variations October 2009	19	Yes

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240	CitiPower's Specialist Metering Checklist	19	No
241	Line Clearance RIS	A6.1	No
242	Powercor Australia's and CitiPower's Response to the Line Clearance RIS, 20 May 2010.	A6.1	No
243	ESCV Appeal Panel Decision	A6.1, 14	No
244	Letter from DLA Phillips Fox to CitiPower and Powercor Australia, 21 June 2010	A6.1	No
245	Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010	A6.1	No
246	Letter from Paul Fearon ESV to Garry Audley Powercor Australia, 7 December 2009	A6.1	No
247	SP Austnet to ESV dated 10 May 2010 regarding Proposed Electricity Safety (Electric Line Clearance) Regulations 2010 – Regulatory Impact Statement	A6.1	No
248	Documents referred to in Chronology of Vegetation Management Compliance	A6.1	No
249	Letter from SP AusNet to CitiPower dated 6 May 2010	6	No
250	Cost build up model for demand management at WMTS step change	6	Yes
251	Victorian DNSPs, Transmission Connection Planning Report produced jointly by the Victorian Electricity Distribution Businesses, 2009	1, 6, 9	No
252	CitiPower, Melbourne CBD Security of Supply Project Plan, 16 June 2008	9	No
253	Letter from ESCV approving security of supply upgrade plan, 18 August 2008	9	No
254	ESCV, Final Decision CBD Security of Supply, February 2008	9	No
255	CitiPower, Melbourne CBD Security of Supply Enhancement Project, Submission to the Essential Services Commission, 11 September 2006	9	No
256	Maunsell, VM Substation Options Report, 31 March 2009	9	No
257	Metro 2012 and CBD security of supply quote tables, 8 July 2010	9	Yes
258	Powercor Network Services, Metro 2012 & CBD Security Building Modifications – Civil Design, W Zone Substation, May 2010	9	No
259	CitiPower / PNS, Memo to the Board of Directors regarding supplier recommendation for network services activities, 25 May 2010	9	Yes

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260	City of Melbourne, 1200 Buildings Melbourne's Building Retrofit Project, Steering Committee Terms of Reference, 3 February 2009	9	No
261	ESCV, Letter to CitiPower regarding management of fault current level within CitiPower's distribution network, 17 October 2008	9	No
262	Confidential, major customer complaint received May 2009 regarding voltage level supplied from FR zone substation	9	Yes
263	CitiPower, Graph of bus voltage from FR zone substation in April 2009	9	Yes
264	Wilkins, Dennis J., The Bathtub Curve and Product Failure Behavior, Part One – The Bathtub Curve, Infant Mortality and Burn-in, HotWire, November 2002	9	No
265	Wilkins, Dennis J., The Bathtub Curve and Product Failure Behavior, Part Two – Normal Life and Wear-Out, HotWire, December 2002	9	No
266	CEG, Detailed application of AER cost of debt methodology to alternative bond samples, A report for Victorian DBs, July 2010	12	No

Appendix 3.1 – Implementation Formulae for P_t, TRC_t, T_t, and KAY_t Terms

In this Appendix, CitiPower details its proposed formulae to calculate the P_t, TRC_t, T_t and KAY_t, terms in the WAPC formula.

A worked example of the application of these implementation formulae is set out in the Worked Example of Pass-through Factor Model (Attachment 18 to this Revised Regulatory Proposal).

Pass Through Implementation Formulae

The WAPC terms must be calculated in the correct sequence as each factor feeds into the calculation of the subsequent factors. This is necessary to ensure the correct treatment of each term. In the case of *P* factor the term must be calculated after *CPI, X, S* and *L* factors.

1. Passthrough factor

The passthrough adjustment (P_t) to the WAPC and in the *regulatory year t*, for a given DNSP is expressed by the formula set out below.

The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

The passthrough adjustment (P_t) that will apply in *regulatory year t* after the regulatory year ending 31 December 2010, for each DNSP, is:

$$P_t = \left(\frac{1 + P'_t}{1 + P'_{t-1}} \right) - 1$$

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"*
P_t	is the passthrough factor which is calculated by determining the raw passthrough factor for *regulatory* year *t* and backing out the raw passthrough factor for *regulatory year t-1*
P'_t	is calculated in accordance with section 2 for *regulatory year t*
P'_{t-1}	(a) if *regulatory* year *t* is prior to calendar year ending 31 December 2012, is zero

(b) if *regulatory* year t is after calendar year ending 31 December 2011, is the value of P'_t determined in the *regulatory year t–1*

2. Calculation of P'_t

P'_t is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$P'_t = \frac{MPR_t}{Rf_t}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
P'_t	is the raw calculated passthrough factor for *regulatory year t* only.
MPR_t	(in ¢) is calculated in accordance with section 3 for *regulatory year t*
Rf_t	(in ¢) is calculated in accordance with section 4 for *regulatory year t*

3. Calculation of MPR_t

MPR_t is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$MPR_t = PCf_t - KP_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
MPR_t	(in ¢) is the maximum revenue the DNSP is allowed to receive from passthrough revenue from all distribution customers for the *regulatory year t*
PCf_t	(in ¢) is the aggregate of all forecast passthrough factor charges and forecast passthrough factor revenues which the distribution business is expected to pay and entitled to receive in *regulatory year t*
KP_t	(in ¢) is determined in accordance with section 3.1 for *regulatory year t*

3.1. Correction Factor KP_t

KP_t is determined by reference to the formula set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KP_t = (KPy_t + KPz_t + KP_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

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"*
KP_t	(in ¢) is a correction factor to account for any under or over recovery of actual passthrough revenue for *regulatory year t−1*
KPy_t	(in ¢) is calculated in accordance with section 3.1.1 for *regulatory year t*
KPz_t	(in ¢) is calculated in accordance with section 3.1.2 for *regulatory year t*
KP_{t-1}	(in ¢) is the figure calculated for KP_t for *regulatory year t−1*
$pretax\ WACC_D$	is as set out in the Post Tax Revenue Model (*PTRM*) as determined in the Final Determination for the relevant distribution business.
CPI_t	is CPI for *regulatory year t*, calculated as set out in the WAPC formula.

3.1.1. Calculation of KPy_t

KPy_t is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KPy_t = PRe_{t-1} - PCe_{t-1}$$

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"*
KPy_t	(in ¢) is a correction factor for *regulatory year t-1*

PRe_{t-1}	(in ¢) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*
PCe_{t-1}	(in ¢) is the aggregate of all estimated passthrough factor charges and estimated passthrough factor revenues which the distribution business is expected to pay and entitled to receive in *regulatory year t-1*

3.1.1.1. Estimated Passthrough Revenue (*PRe_t*)

PRe_t is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$PRe_t = \left(\sum_{i=1}^{n} \sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t \right) \times P'_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
PRe_t	(in ¢) the total revenue which it is estimated the distribution business will earn from its passthrough factor in respect of all distribution customers in *regulatory year t*
p'^{ij}_t	is calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the estimated quantity of distribution tariff component *j* of distribution tariff *i* in *regulatory year t*
P'_t	is calculated in accordance with section 2 in *regulatory year t*

3.1.2. Calculation of *KPz_t*

KPz_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KPz_t = \{(PRa_{t-2} - PRe_{t-2}) - (PCa_{t-2} - PCe_{t-2})\} \times (1 + pretaxWACC_D) \times (1 + CPI_{t-1})$$

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"*

KPz_t (in ¢) is a correction amount for the difference between amounts calculated in section 3.1.1 in *regulatory year t−1* and actual values

PRa_{t-2} (in ¢) is calculated in accordance with section 3.1.2.1 in *regulatory year t−2*

PRe_{t-2} (in ¢) is the figure used for PRe_{t-1} when calculating KPy_t under section 3.1.1 for *regulatory year t−1*

PCa_{t-2} (in ¢) is the audited aggregate of all passthrough factor charges and passthrough factor revenues which were paid or received by the distribution business, where passthrough amounts approved by the AER for *regulatory year t−2*

PCe_{t-2} (in ¢) is the amount calculated for PCe_{t-1} when calculating KPy_t under section 3.1.1 for *regulatory year t−1*

CPI_{t-1} is as set out in section 3.1

pretax $WACC_D$ is as set out in section 3.1

3.1.2.1.Calculation of PRa_t

PRa_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$PRa_t = Ra_t - Ra''_t$$

Where

regulatory year "t" is the regulatory year in respect of which the calculation is being made

PRa_t (in ¢) is the calculated revenue earned by the distribution business from the P factor in *regulatory year t*

Ra_t (in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*

Ra''_t (in ¢) is calculated in accordance with section 3.1.2.1.2 for *regulatory year t*

3.1.2.1.1. Calculation of Ra_t

Ra_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra_t = \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_t^{ij}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra_t	(in ¢) is the calculated Weighted Average Price Cap (WAPC) revenue earned in *regulatory year t*
$p^{ij}{}_t$	is the distribution tariff rate for component j of distribution tariff i in regulatory year t
$q^{ij}{}_t$	is the actual audited quantity of distribution tariff component j of distribution tariff i in regulatory year t

3.1.2.1.2. Calculation of Ra''_t

Ra''_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra_t = \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_t^{ij}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra''_t	(in ¢) is the calculated revenue earned without P' factor in *regulatory year t*
Ra_t	(in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*
P'_t	is calculated in accordance with section 2 for *regulatory year t*

4. Calculation of Rf_t

Rf_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Rf_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Rf_t	(in ¢) is the forecast revenue expected to be earned without the P_t in the *regulatory year t*
p'^{ij}_t	is the distribution tariff rate for component j of distribution tariff i in regulatory year t calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the forecast quantity of distribution tariff component j of distribution tariff i in *regulatory year t*

4.1. Price without current year *P* factor

p'^{ij}_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$p'^{ij}_t = p^{ij}_{t-1} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t)$$

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"*
p'^{ij}_t	is the theoretical price of the distribution tariff rate in *regulatory year t* without the P_t for each tariff component j of tariff i
p^{ij}_{t-1}	is the distribution tariff rate for component j of distribution tariff i in regulatory year $t-1$
CPI_t	is as set out in section 3.1 for *regulatory year t*

X_t	is the value of X for year *t* of the regulatory control period as determined by the AER
S_t	is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*
L_t	is the licence fee adjustment to be applied in regulatory year *t*

Transmission-Related Costs Implementation Formulae

The WAPC terms must be calculated in the correct sequence as each factor feeds into the calculation of the subsequent factors. This is necessary to ensure the correct treatment of each term. In the case of *TRC* factor the term must be calculated after *CPI, X, S, L* and *P* factors.

1. Transmission-related costs factor

The transmission-related costs adjustment (TRC_t) to the WAPC and in the *regulatory year t*, for a given DNSP is expressed by the formula set out below.

The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

The transmission-related costs adjustment (TRC_t) that will apply in *regulatory year t* after the regulatory year ending 31 December 2010, for each DNSP, is:

$$TRC_t = \left(\frac{1 + TRC'_t}{1 + TRC'_{t-1}} \right) - 1$$

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"*
TRC_t	is the transmission-related costs factor which is calculated by determining the transmission-related costs factor for *regulatory* year *t* and backing out the transmission-related costs factor for *regulatory year t-1*
TRC'_t	is calculated in accordance with section 2 for *regulatory year t*
TRC'_{t-1}	(a) if *regulatory* year *t* is prior to calendar year ending 31 December 2012, is zero (b) if *regulatory* year *t* is after calendar year ending 31 December 2011, is the value of TRC'$_t$ determined in the *regulatory year t–1*

2. Calculation of TRC'_t

TRC'_t is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$TRC'_t = \frac{MTRCR_t}{Rf_t}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
TRC'_t	is the calculated transmission-related costs factor for *regulatory year t* only.
$MTRCR_t$	(in ¢) is calculated in accordance with section 3 for *regulatory year t*
Rf_t	(in ¢) is calculated in accordance with section 4 for *regulatory year t*

3. Calculation of $MTRCR_t$

$MTRCR_t$ is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$MTRCR_t = TRCCf_t - KTRC_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
$MTRCR_t$	(in ¢) is the maximum revenue the DNSP is allowed to receive from transmission-related costs revenue from all distribution customers for the *regulatory year t*
$TRCCf_t$	(in ¢) is the aggregate of all forecast transmission-related costs factor charges which the distribution business is expected to pay in *regulatory year t*
$KTRC_t$	(in ¢) is determined in accordance with section 3.1 for *regulatory year t*

3.1. Correction Factor $KTRC_t$

$KTRC_t$ is determined by reference to the formula set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KTRC_t = (KTRCy_t + KTRCz_t + KTRC_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

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"*
$KTRC_t$	(in ¢) is a correction factor to account for any under or over recovery of actual transmission-related costs revenue for *regulatory year t−1*
$KTRCy_t$	(in ¢) is calculated in accordance with section 3.1.1 for *regulatory year t*
$KTRCz_t$	(in ¢) is calculated in accordance with section 3.1.2 for *regulatory year t*
$KTRC_{t-1}$	(in ¢) is the figure calculated for $KTRC_t$ for *regulatory year t−1*
pretax $WACC_D$	is as set out in the Post Tax Revenue Model (*PTRM*) as determined in the Final Determination for the relevant distribution business.
CPI_t	is CPI for *regulatory year t*, calculated as set out in the WAPC formula.

3.1.1. Calculation of $KTRCy_t$

$KTRCy_t$ is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KTRCy_t = TRCRe_{t-1} - TRCCe_{t-1}$$

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"*
$KTRCy_t$	(in ¢) is a correction factor for *regulatory year t-1*
$TRCRe_{t-1}$	(in ¢) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*
$TRCCe_{t-1}$	(in ¢) is the aggregate of all estimated transmission-related costs factor charges which the distribution business is expected to pay in *regulatory year t-1*

3.1.1.1.Estimated Transmission-related costs Revenue (*$TRCRe_t$*)

$TRCRe_t$ is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$TRCRe_t = \left(\sum_{i=1}^{n} \sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t \right) \times TRC'_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
$TRCRe_t$	(in ¢) the total revenue which it is estimated the distribution business will earn from its transmission-related costs factor in respect of all distribution customers in *regulatory year t*
p'^{ij}_t	is calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the estimated quantity of distribution tariff component *j* of distribution tariff *i* in *regulatory year t*
TRC'_t	is calculated in accordance with section 2 in *regulatory year t*

3.1.2. Calculation of *$KTRCz_t$*

$KTRCz_t$ is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KTRCz_t = \{(TRCRa_{t-2} - TRCRe_{t-2}) - (TRCCa_{t-2} - TRCCe_{t-2})\} \times (1 + pretaxWACC_D) \times (1 + CPI_{t-1})$$

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"*
$KTRCz_t$	(in ¢) is a correction amount for the difference between amounts calculated in section 3.1.1 in *regulatory year t−1* and actual values
$TRCRa_{t-2}$	(in ¢) is calculated in accordance with section 3.1.2.1 in *regulatory year t−2*

$TRCRe_{t-2}$	(in ¢) is the figure used for $TRCRe_{t-1}$ when calculating $KTRCy_t$ under section 3.1.1 for *regulatory year t−1*
$TRCCa_{t-2}$	(in ¢) is the audited aggregate of all transmission-related costs factor charges and transmission-related costs factor revenues which were paid or received by the distribution business, where transmission-related costs amounts are approved by the AER for *regulatory year t−2*
$TRCCe_{t-2}$	(in ¢) is the amount calculated for $TRCCe_{t-1}$ when calculating $KTRCy_t$ under section 3.1.1 for *regulatory year t−1*
CPI_{t-1}	is as set out in section 3.1
pretax $WACC_D$	is as set out in section 3.1

3.1.2.1.Calculation of $TRCRa_t$

$TRCRa_t$ is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$TRCRa_t = Ra_t - Ra''_t$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
$TRCRa_t$	(in ¢) is the calculated revenue earned by the distribution business from the *TRC* factor in *regulatory year t*
Ra_t	(in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*
Ra''_t	(in ¢) is calculated in accordance with section 3.1.2.1.2 for *regulatory year t*

3.1.2.1.1. Calculation of Ra_t

Ra_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra_t = \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_t^{ij}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra_t	(in ¢) is the calculated Weighted Average Price Cap (WAPC) revenue earned in *regulatory year t*
p^{ij}_t	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t*
q^{ij}_t	is the actual audited quantity of distribution tariff component *j* of distribution tariff *i* in regulatory year *t*

3.1.2.1.2. Calculation of Ra''_t

Ra''_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra''_t = \frac{Ra_t}{(1+TRC'_t)}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra''_t	(in ¢) is the calculated revenue earned without *TRC'* factor in *regulatory year t*
Ra_t	(in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*
TRC'_t	is calculated in accordance with section 2 for *regulatory year t*

4. Calculation of Rf_t

Rf_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Rf_t = \sum_{i=1}^{n}\sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Rf_t	(in ¢) is the forecast revenue expected to be earned without the TRC_t in the *regulatory year t*
p'^{ij}_t	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t* calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the forecast quantity of distribution tariff component *j* of distribution tariff *i* in *regulatory year t*

4.1. Price without current year *TRC* factor

p'^{ij}_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$p'^{ij}_t = p^{ij}_{t-1} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \times (1 + P_t)$$

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"*
p'^{ij}_t	is the theoretical price of the distribution tariff rate in *regulatory year t* without the TRC_t for each tariff component *j* of tariff *i*
p^{ij}_{t-1}	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t-1*
CPI_t	is as set out in section 3.1 for *regulatory year t*
X_t	is the value of X for year *t* of the regulatory control period as determined by the AER
S_t	is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*
L_t	is the licence fee adjustment to be applied in regulatory year *t*
P_t	is passthrough adjustment for *regulatory year t*

S-Factor true-up Implementation Formulae

The WAPC terms must be calculated in the correct sequence as each factor feeds into the calculation of the subsequent factors. This is necessary to ensure the correct treatment of each term. In the case of *T* factor the term must be calculated after *CPI, X, S, L, P* and *TRC* factors.

1. S-Factor true-up factor

The S-Factor true-up factor (T_t) to the WAPC and in the *regulatory year t*, for a given DNSP is expressed by the formula set out below.

The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

The S-Factor true-up factor (T_t) that will apply in *regulatory year t* after the regulatory year ending 31 December 2010, for each DNSP, is:

$$T_t = \left(\frac{1 + T'_t}{1 + T'_{t-1}} \right) - 1$$

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"*
T_t	is the S-Factor true-up factor which is calculated by determining the S-Factor true-up factor for *regulatory* year *t* and backing out the S-factor true-up factor for *regulatory year t-1*
T'_t	is calculated in accordance with section 2 for *regulatory year t*
T'_{t-1}	(a) if *regulatory* year *t* is prior to calendar year ending 31 December 2012, is zero (b) if *regulatory* year *t* is after calendar year ending 31 December 2011, is the value of T'_t determined in the *regulatory year t–1*

2. Calculation of T'_t

T'_t is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$T'_t = \frac{MSR_t}{Rf_t}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
T'_t	is the calculated S-Factor true-up factor for *regulatory year t* only.
MSR_t	(in ¢) is calculated in accordance with section 3 for *regulatory year t*
Rf_t	(in ¢) is calculated in accordance with section 4 for *regulatory year t*

3. Calculation of MSR_t

MSR_t is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$MSR_t = TCf_t - KT_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
MSR_t	(in ¢) is the maximum revenue the DNSP is allowed to receive from S-Factor true-up revenue from all distribution customers for the *regulatory year t*
TCf_t	(in ¢) is the aggregate of all forecast S-Factor true-up factor charges and forecast S-Factor true-up factor revenues which the distribution business is expected to pay and entitled to receive in *regulatory year t*
KT_t	(in ¢) is determined in accordance with section 3.1 for *regulatory year t*

3.1. Correction Factor KT_t

KT_t is determined by reference to the formula set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KT_t = (KTy_t + KTz_t + KT_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

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"*
KT_t	(in ¢) is a correction factor to account for any under or over recovery of actual S-Factor true-up revenue for *regulatory year t−1*
KTy_t	(in ¢) is calculated in accordance with section 3.1.1 for *regulatory year t*
KTz_t	(in ¢) is calculated in accordance with section 3.1.2 for *regulatory year t*
KT_{t-1}	(in ¢) is the figure calculated for KT_t for *regulatory year t−1*
pretax $WACC_D$	is as set out in the Post Tax Revenue Model (*PTRM*) as determined in the Final Determination for the relevant distribution business.
CPI_t	is CPI for *regulatory year t*, calculated as set out in the WAPC formula.

3.1.1. Calculation of KTy_t

KTy_t is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KTy_t = TRe_{t-1} - TCe_{t-1}$$

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"*
KTy_t	(in ¢) is a correction factor for *regulatory year t-1*
TRe_{t-1}	(in ¢) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*
TCe_{t-1}	(in ¢) is the aggregate of all estimated S-Factor true-up factor charges and estimated S-Factor true-up factor revenues which the distribution business is expected to pay and entitled to receive in *regulatory year t-1*

3.1.1.1.Estimated S-Factor true-up Revenue (TRe_t)

TRe_t is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$TRe_t = \left(\sum_{i=1}^{n} \sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t \right) \times T'_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
TRe_t	(in ¢) the total revenue which it is estimated the distribution business will earn from its S-Factor true-up factor in respect of all distribution customers in *regulatory year t*
p'^{ij}_t	is calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the estimated quantity of distribution tariff component *j* of distribution tariff *i* in *regulatory year t*
T'_t	is calculated in accordance with section 2 in *regulatory year t*

3.1.2. Calculation of KTz_t

KTz_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KTz_t = \{(TRa_{t-2} - TRe_{t-2}) - (TCa_{t-2} - TCe_{t-2})\} \times (1 + pretaxWACC_D) \times (1 + CPI_{t-1})$$

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"*
KTz_t	(in ¢) is a correction amount for the difference between amounts calculated in section 3.1.1 in *regulatory year t−1* and actual values
TRa_{t-2}	(in ¢) is calculated in accordance with section 3.1.2.1 in *regulatory year t−2*

TRe_{t-2}	(in ¢) is the figure used for TRe_{t-1} when calculating KTy_t under section 3.1.1 for *regulatory year t−1*
TCa_{t-2}	(in ¢) is the audited aggregate of all S-Factor true-up factor charges and S-Factor true-up factor revenues which were paid or received by the distribution business, where S-factor true-up amounts approved by the AER for *regulatory year t−2*
TCe_{t-2}	(in ¢) is the amount calculated for TCe_{t-1} when calculating KTy_t under section 3.1.1 for *regulatory year t−1*
CPI_{t-1}	is as set out in section 3.1
pretax $WACC_D$	is as set out in section 3.1

3.1.2.1.Calculation of TRa_t

TRa_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$TRa_t = Ra_t - Ra''_t$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
TRa_t	(in ¢) is the calculated revenue earned by the distribution business from the *T* factor in *regulatory year t*
Ra_t	(in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*
Ra''_t	(in ¢) is calculated in accordance with section 3.1.2.1.2 for *regulatory year t*

3.1.2.1.1. Calculation of Ra_t

Ra_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra_t = \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_t^{ij}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra_t	(in ¢) is the calculated Weighted Average Price Cap (WAPC) revenue earned in *regulatory year t*
p^{ij}_t	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t*
q^{ij}_t	is the actual audited quantity of distribution tariff component *j* of distribution tariff *i* in regulatory year *t*

3.1.2.1.2. Calculation of Ra''_t

Ra''_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra''_t = \frac{Ra_t}{(1 + T'_t)}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra''_t	(in ¢) is the calculated revenue earned without T' factor in *regulatory year t*
Ra_t	(in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*
T'_t	is calculated in accordance with section 2 for *regulatory year t*

4. Calculation of Rf_t

Rf_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Rf_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Rf_t	(in ¢) is the forecast revenue expected to be earned without the T_t in the *regulatory year t*
p'^{ij}_t	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t* calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the forecast quantity of distribution tariff component *j* of distribution tariff *i* in *regulatory year t*

4.1. Price without current year *T* factor

p'^{ij}_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$p'^{ij}_t = p^{ij}_{t-1} \times (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\times\left(1+P_t\right)\times(1+TRC_t)$$

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"*
p'^{ij}_t	is the theoretical price of the distribution tariff rate in *regulatory year t* without the P_t for each tariff component *j* of tariff *i*
p^{ij}_{t-1}	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t-1*
CPI_t	is as set out in section 3.1 for *regulatory year t*
X_t	is the value of X for year *t* of the regulatory control period as determined by the AER
S_t	is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*
L_t	is the licence fee adjustment to be applied in regulatory year *t*
P_t	is passthrough adjustment for *regulatory year t*
TRC_t	is transmission-related costs for *regulatory year t*

K-Factor True-up Implementation Formulae

The WAPC terms must be calculated in the correct sequence as each factor feeds into the calculation of the subsequent factors. This is necessary to ensure the correct treatment of each term. In the case of *KAY* factor the term must be calculated after *CPI, X, S, L, P, TRC,* and *T* factors.

1. K-Factor True-up factor

The K-Factor True-up factor (KAY_t) to the WAPC and in the *regulatory year t*, for a given DNSP is expressed by the formula set out below.

The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

The K-Factor True-up factor (KAY_t) that will apply in *regulatory year t* after the regulatory year ending 31 December 2010, for each DNSP, is:

$$KAY_t = \left(\frac{1 + KAY'_t}{1 + KAY'_{t-1}} \right) - 1$$

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"*
KAY_t	is the K-Factor True-up factor which is calculated by determining the raw K-Factor True-up factor for *regulatory* year *t* and backing out the raw K-Factor True-up factor for *regulatory year t-1*
KAY'_t	is calculated in accordance with section 2 for *regulatory year t*
KAY'_{t-1}	(a) if *regulatory* year *t* is prior to calendar year ending 31 December 2012, is zero (b) if *regulatory* year *t* is after calendar year ending 31 December 2011, is the value of KAY'_t determined in the *regulatory year t–1*

2. Calculation of KAY'_t

KAY'_t is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KAY'_t = \frac{MKAYR_t}{Rf_t}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
KAY'_t	is the calculated raw K-factor true-up factor for *regulatory year t* only.
$MKAYR_t$	(in ¢) is calculated in accordance with section 3 for *regulatory year t*
Rf_t	(in ¢) is calculated in accordance with section 4 for *regulatory year t*

3. Calculation of $MKAYR_t$

$MKAYR_t$ is expressed by the formula as set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$MKAYR_t = KAYCf_t - KKAY_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
$MKAYR_t$	(in ¢) is the maximum revenue the DNSP is allowed to receive from K-Factor True-up revenue from all distribution customers for the *regulatory year t*
$KAYCf_t$	(in ¢) is the aggregate of all forecast K-Factor True-up factor charges and forecast K-Factor True-up factor revenues which the distribution business is expected to pay and entitled to receive in *regulatory year t*
$KKAY_t$	(in ¢) is determined in accordance with section 3.1 for *regulatory year t*

3.1. Correction Factor $KKAY_t$

$KKAY_t$ is determined by reference to the formula set out below. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KKAY_t = (KKAYy_t + KKAYz_t + KKAY_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

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"*

$KKAY_t$ (in ¢) is a correction factor to account for any under or over recovery of actual K-Factor True-up revenue for *regulatory year t−1*

$KKAYy_t$ (in ¢) is calculated in accordance with section 3.1.1 for *regulatory year t*

$KKAYz_t$ (in ¢) is calculated in accordance with section 3.1.2 for *regulatory year t*

$KKAY_{t-1}$ (in ¢) is the figure calculated for $KKAY_t$ for *regulatory year t−1*

pretax $WACC_D$ is as set out in the Post Tax Revenue Model (*PTRM*) as determined in the Final Determination for the relevant distribution business.

CPI_t is CPI for *regulatory year t*, calculated as set out in the WAPC formula.

3.1.1. Calculation of $KKAYy_t$

$KKAYy_t$ is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KKAYy_t = KAYRe_{t-1} - KAYCe_{t-1}$$

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"*

$KKAYy_t$ (in ¢) is a correction factor for *regulatory year t-1*

$KAYRe_{t-1}$ (in ¢) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*

$KAYCe_{t-1}$ (in ¢) is the aggregate of all estimated K-Factor True-up factor charges and estimated K-Factor True-up factor revenues which the distribution business is expected to pay and entitled to receive in *regulatory year t-1*

3.1.1.1. Estimated K-Factor True-up Revenue ($KAYRe_t$)

$KAYRe_t$ is determined with reference to the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KAYRe_t = \left(\sum_{i=1}^{n} \sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t \right) \times KAY'_t$$

Where:

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
$KAYRe_t$	(in ¢) the total revenue which it is estimated the distribution business will earn from its K-Factor True-up factor in respect of all distribution customers in *regulatory year t*
p'^{ij}_t	is calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the estimated quantity of distribution tariff component *j* of distribution tariff *i* in *regulatory year t*
KAY'_t	is calculated in accordance with section 2 in *regulatory year t*

3.1.2. Calculation of $KKAYz_t$

$KKAYz_t$ is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KKAYz_t = \{(KAYRa_{t-2} - KAYRe_{t-2}) - (KAYCa_{t-2} - KAYCe_{t-2})\} \times (1 + pretaxWACC_D) \times (1 + CPI_{t-1})$$

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"*
$KKAYz_t$	(in ¢) is a correction amount for the difference between amounts calculated in section 3.1.1 in *regulatory year t−1* and actual values
$KAYRa_{t-2}$	(in ¢) is calculated in accordance with section 3.1.2.1 in *regulatory year t−2*

$KAYRe_{t-2}$ (in ¢) is the figure used for $KAYRe_{t-1}$ when calculating $KKAYy_t$ under section 3.1.1 for *regulatory year t−1*

$KAYCa_{t-2}$ (in ¢) is the audited aggregate of all K-Factor True-up factor charges and K-Factor True-up factor revenues which were paid or received by the distribution business, where K-Factor True-up amounts approved by the AER for *regulatory year t−2*

$KAYCe_{t-2}$ (in ¢) is the amount calculated for $KAYCe_{t-1}$ when calculating $KKAYy_t$ under section 3.1.1 for *regulatory year t−1*

CPI_{t-1} is as set out in section 3.1

pretax $WACC_D$ is as set out in section 3.1

3.1.2.1.Calculation of $KAYRa_t$

$KAYRa_t$ is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$KAYRa_t = Ra_t - Ra''_t$$

Where

regulatory year "t" is the regulatory year in respect of which the calculation is being made

$KAYRa_t$ (in ¢) is the calculated revenue earned by the distribution business from the *KAY* factor in *regulatory year t*

Ra_t (in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*

Ra'_t (in ¢) is calculated in accordance with section 3.1.2.1.2 for *regulatory year t*

3.1.2.1.1. Calculation of Ra_t

Ra_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra_t = \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_t^{ij}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra_t	(in ¢) is the calculated Weighted Average Price Cap (WAPC) revenue earned in *regulatory year t*
$p^{ij}{}_t$	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t*
$q^{ij}{}_t$	is the actual audited quantity of distribution tariff component *j* of distribution tariff *i* in regulatory year *t*

3.1.2.1.2. Calculation of Ra''_t

Ra''_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Ra''_t = \frac{Ra_t}{(1 + KAY'_t)}$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Ra''_t	(in ¢) is the calculated revenue earned without *KAY'* factor in *regulatory year t*
Ra_t	(in ¢) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*
KAY'_t	is calculated in accordance with section 2 for *regulatory year t*

4. Calculation of Rf_t

Rf_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$Rf_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p'^{ij}_t \times q^{ij}_t$$

Where

regulatory year "t"	is the regulatory year in respect of which the calculation is being made
Rf_t	(in ¢) is the forecast revenue expected to be earned without the KAY_t in the *regulatory year t*
p'^{ij}_t	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t* calculated in accordance with section 4.1 for *regulatory year t*
q^{ij}_t	is the forecast quantity of distribution tariff component *j* of distribution tariff *i* in *regulatory year t*

4.1. Price without current year *KAY* factor

p'^{ij}_t is expressed by the formula in this section. The formula may be amended by the AER but only for the purpose of correcting manifest errors and/or omissions and only after consulting with relevant stakeholders.

$$p'^{ij}_t = p^{ij}_{t-1} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \times (1 + P_t) \times (1 + TRC_t) \times (1 + T_t)$$

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"*
p'^{ij}_t	is the theoretical price of the distribution tariff rate in *regulatory year t* without the KAY_t for each tariff component *j* of tariff *i*
p^{ij}_{t-1}	is the distribution tariff rate for component *j* of distribution tariff *i* in regulatory year *t-1*
CPI_t	is as set out in section 3.1 for *regulatory year t*
X_t	is the value of X for year *t* of the regulatory control period as determined by the AER
S_t	is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*
L_t	is the licence fee adjustment to be applied in regulatory year *t*
P_t	is passthrough adjustment for *regulatory year t*
TRC_t	is transmission-related costs for *regulatory year t*
T_t	is S-Factor true up for *regulatory year t*

Appendix 5.1 - Proper Construction and Application to Outsourcing Arrangements of Opex and Capex Criteria

This Appendix 5.1 is intended to be read in conjunction with Chapter 5 of this Revised Regulatory Proposal.

It sets out the detailed legal reasoning and analysis that supports CitiPower's views detailed in Chapter 5, section 5.5.1.1 of the Revised Regulatory Proposal on the proper construction and application to outsourcing arrangements of the opex and capex criteria, including in particular on:

- the proper construction and application of the prudency criterion;
- the proper construction and application of the efficiency criterion; and
- the AER's discretion to balance the competing efficiency and prudency criteria.

CitiPower's legal analysis, set out in this Appendix, demonstrates that the AER erred in the Draft Determination in concluding that:

- the Rules permit it to assess a DNSP's expenditure forecasts having regard to the costs that would be incurred by the group to which the DNSP belongs rather than the costs that would be incurred in the services were provided on a 'fully in-sourced, standalone' basis or the costs that would be incurred by the DNSP itself having regard to its group structure; and
- the efficient costs of the DNSP would not include any margin above its contractor's directly incurred costs in respect of historical scale and scope, and other, efficiencies because such a margin could not be charged by that contractor in a workably competitive market.

Briefly stated, CitiPower's views on the proper construction and application of the prudency and efficiency criteria and the AER's discretion to balance these competing criteria are as follows:

- The phrase *'in the circumstances of the relevant* Distribution Network Service Provider*'*, where it appears in the prudency criterion, does not permit the AER to have regard to the group structure of a DNSP in assessing its expenditure forecasts because:
    - in properly construing this phrase, a purposive rather than a literal interpretation must be adopted; and
    - the circumstances of the DNSP to which the prudency criterion refers were intended to require a consideration of the network operating conditions of the DNSP and not its group structure.
- In any event, even if the circumstances of the DNSP referred to in the prudency criterion include the group structure of the DNSP, it does not follow that the prudency criterion permits the AER to assess the DNSP's expenditure forecasts against the costs that would be incurred by the group to which the DNSP belongs because:

  - the prudency criterion refers to *'the circumstances of the relevant* Distribution Network Service Provider*'* and not to the circumstances of the group to which that DNSP belongs and, accordingly, requires an inquiry into the costs that the DNSP itself (as distinct from the group to which it belongs), acting prudently, would require to achieve the opex and/or capex objectives;
  - it cannot be assumed that scale and scope efficiencies achievable by the group are necessarily available at no cost to the DNSP, acting prudently; and
  - it follows that the AER cannot exclude any scale and scope efficiencies achievable by the group to which a DNSP belongs from the benchmark costs against which a DNSP's expenditure forecasts are assessed in applying the prudency criterion, except where the AER satisfies itself that those efficiencies could be accessed without cost (i.e. margin) by the DNSP, acting prudently.

- While CitiPower accepts that the efficiency criterion, properly construed and applied, necessitates an inquiry into pricing outcomes in a workably competitive market, it disagrees with the AER that it follows that historical efficiencies realised by another entity in the group to which the DNSP belongs do not warrant payment of an amount in excess of the contractor's directly incurred costs. To the contrary, the decision of the Tribunal, in *Application by Optus Mobile Pty Limited and Optus Networks Pty Limited,* [1]establishes that:
  - in a workably competitive market, a service provider may gain a competitive advantage by having access to economies of scale and scope by reason of its ownership and operation of other networks in addition to the regulated network; and
  - accordingly, the stand-alone, in-house costs of service provision is the cost benchmark that best reflects the pricing outcomes that would prevail in a workably competitive market.

- In striking a reasonable balance between the efficiency and prudency criteria, the AER has no discretion to reduce a DNSP's expenditure forecasts below the efficient costs of achieving the opex and capex objectives, on the basis of its assessment of that expenditure forecast against the prudency criterion, because:
  - in exercising its discretion to balance the efficiency and prudency criteria, the AER must do so in a manner that is likely to contribute to the achievement of the NEO and takes into account the revenue and pricing principles;[2] and
  - the Tribunal concluded in *Application of Energy Australia and Others* that the NEO and the revenue and pricing principles require

[1] [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].
[2] NEL, section 16; [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [14] & [74].

> that the regulatory setting of prices *'err on the side of allowing at least the recovery of efficient costs'*.[3]

Construction and application of the prudency criterion

As discussed in section 5.4.2 above, the AER concluded in the Draft Determination that a margin is not necessary to compensate contractors for economies of scale and scope if the DNSP could access those economies through the group structure of the DNSP. That is, the related party expenditure is assessed against the costs that would be incurred by the group to which the DNSP belongs and not against those of a hypothetical 'fully in-sourced, standalone' network.

Critical to the AER's conclusion that expenditure forecasts should be assessed against the costs that would be incurred by the group to which the DNSP belongs and not against those of a hypothetical 'fully in-sourced, standalone' network is its construction of the prudency criterion. The AER's conclusion turns on its construction of the phrase *'in the circumstances of the relevant* Distribution Network Service Provider' where it appears in the prudency criterion. The AER reasoned as follows regarding the construction of this phrase:[4]

> *'It appears reasonable to conclude that the 'circumstances' of the DNSP includes its ownership structure, and in particular whether or not it is part of a large group of networks giving it access to economies of scale, scope and other efficiencies that wouldn't be available to a hypothetical 'standalone' network.*
>
> …
>
> *Accordingly, a 'standalone' cost standard would only appear appropriate it [sic] that reflects the circumstances under which the service provider is found in. However, where a service provider is part of a larger corporate group that owns and operates multiple networks, then these are the circumstances that service provider is found in, and accordingly this fact is important in assessment the costs that would be incurred by a prudent operator in the circumstances of that DNSP.'*

In construing the prudency criterion, the AER does not appear to have given any consideration to the statutory purpose or drafting intent of the inclusion of the phrase *'in the circumstances of the relevant* Distribution Network Service Provider', including in particular whether the inclusion of this phrase was intended to permit regard to be had to the group structure of a DNSP in assessing its expenditure forecasts. CitiPower submits that consideration of this statutory purpose or drafting intent is essential to the proper construction of the prudency criterion. CitiPower reminds the AER that the Rules are to be given a purposive rather than a literal interpretation.[5]

[3] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [78].
[4] AER, Draft Determination, p179.
[5] Section 7 of Schedule 2 to the NEL provides that *'[i]n the interpretation of a provision of this Law, the interpretation that will best achieve the purpose or object of this Law is to be preferred to any other interpretation'* and that this *'applies whether or not the purpose is expressly stated in this Law'*. Section 3 of the NEL provides that Schedule 2 to the NEL applies to the Rules; see also section 41 of Schedule 2 to the NEL.

CitiPower considers that the statutory intent, in including the phrase *'in the circumstances of the relevant* Distribution Network Service Provider*'* in the prudency criterion, was not to allow for regard to be had to the group structure of a DNSP in assessing its expenditure forecasts. Rather, the circumstances of the DNSP to which the prudency criterion refers were intended to require a consideration of the network operating conditions of the DNSP. This is consistent with the AEMC's observation, at the time of introducing analogous opex and capex criteria to Chapter 6A of the Rules, that those criteria were *'more ... operationally focussed'* than the statutory test previously under consideration.[6] It is also consistent with the operation of the prudency criterion as a counter-balance to the efficiency criterion contemplated by the AER's own expert in the review culminating in the NSW Final Determination (discussed further below).

In any event, even if the AER were correct in concluding that *'the circumstances of the relevant* Distribution Network Service Provider*'* referred to in the prudency criterion include its ownership structure, it does not follow that the prudency criterion permits the AER to assess the DNSP's expenditure forecasts against the costs that would be incurred by the group to which the DNSP belongs. In concluding that the prudency criterion permits it to assess the DNSP's expenditure forecasts against the costs that would be incurred by the group to which the DNSP belongs, the AER has misconstrued the prudency criterion.

The prudency criterion refers to the circumstances of the relevant DNSP and not to the circumstances of the group to which that DNSP belongs. It follows that the prudency criterion, read as a whole, requires a consideration of the costs the prudent operator in the circumstances of the DNSP (and not the costs the prudent operator in the circumstances of the group to which the DNSP belongs) would require to achieve the opex and/or opex objectives. The relevant inquiry is one of the costs that the DNSP itself (as distinct from the group to which the DNSP belongs), acting prudently, would require to achieve the opex and/or capex objectives.

Even if the AER is permitted to have regard to the DNSP's ownership structure in making this inquiry, the prudency criterion nonetheless mandates that the AER consider the costs that the DNSP, itself, would incur, acting prudently, and not those costs that the group to which it belongs would incur. It follows that, correctly applied, the prudency criterion does not allow the AER to assess a DNSP's expenditure forecasts against the costs that would be incurred by the group to which the DNSP belong, unless those costs are available to the DNSP acting prudently. That is, the AER cannot exclude any scale and scope efficiencies achievable by the group to which a DNSP belongs from the benchmark costs against which a DNSP's expenditure forecasts are assessed in applying the prudency criterion, without first satisfying itself that those

[6] AEMC, Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18, 16 November 2008 (Attachment 109 to this Revised Regulatory Proposal), p53. In the SCO's Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution Explanatory Material of April 2007 (Attachment 110 to this Revised Regulatory Proposal), the SCO stated (at p5) that *'To achieve the MCE's objective of consistency where appropriate, the Exposure Draft of distribution revenue Rules largely builds on the AEMC's approach to economic regulation of electricity transmission'*.

efficiencies could be accessed without cost (i.e. margin) by the DNSP, acting prudently.

It cannot be assumed that scale and scope efficiencies achievable by the group are necessarily available to a DNSP, acting prudently. Despite the fact that the entities form part of a commonly owned group, they remain separate legal persons for all legal, regulatory and other purposes. By operation of the *Corporations Act 2001* (Cth) and various other laws, each company within the group to which the DNSP belongs owes independent fiduciary, contractual and other obligations to its financiers, creditors, employees and other stakeholders. These obligations of a group entity to third parties cannot be disregarded in dealings with another group entity simply because the two entities fall within the same ultimate ownership structure and it is not correct that superior cost arrangements are necessarily or automatically available simply because that common ownership structure exists. Accordingly, a member of the group may not provide to the DNSP the benefits of the scale and scope efficiencies available to it at no cost because of its legal obligations to third parties.

Where the scale and scope efficiencies achievable by the group are not available at no cost to a DNSP, acting prudently, the AER cannot exclude those efficiencies from the cost benchmark against which it assesses the DNSP's expenditure forecasts in applying the prudency criterion. There may be scope to exclude these efficiencies under the efficiency criterion by reference to the costs that would prevail in a workably competitive market (and the extent to which there is such scope is discussed further below), but it is impermissible for the AER to do so by application of the prudency criterion.

Construction and application of the efficiency criterion

In its Draft Determination, the AER concluded that pricing under outsourcing arrangements is efficient if that pricing is set in a workably competitive market through an open, competitive tender process or mimics pricing outcomes that would prevail in a workably competitive market.[7] It further observed that:[8]

> *'One of the objectives of the regulatory regime is to reflect the outcomes of a competitive market. This is generally regarded as the outcomes of a 'workably' competitive market rather than a 'perfectly' competitive market.'*

It was on this basis that the AER concluded that historical efficiencies do not warrant the payment of an amount in excess of the contractor's directly incurred costs because *'in a workably competitive market a contractor could not [charge a premium (i.e. a margin) above its full economic costs and] earn abnormal profits in the long run for efficiencies it has realised in the past'*.[9]

CitiPower accepts that the efficiency criterion, properly construed and applied, necessitates an inquiry into pricing outcomes in a workably competitive market. However, CitiPower disagrees with the AER that it follows that historical efficiencies realised by another entity in the group to which the DNSP belongs do

[7] AER, Draft Determination, p182.
[8] AER, Draft Determination, p182, in footnote 25.
[9] AER, Draft Determination, p182.

not warrant payment of an amount in excess of the contractor's directly incurred costs.

CitiPower observes that, contrary to the conclusions reached by the AER in the Draft Determination, the Tribunal accepted, in *Application by Optus Mobile Pty Limited and Optus Networks Pty Limited,* [10] that:

- in a workably competitive market, a service provider may gain a competitive advantage by having access to economies of scale and scope by reason of its ownership and operation of other networks in addition to the regulated network; and
- accordingly, the stand-alone, in-house costs of service provision is the cost benchmark that best reflects the pricing outcomes that would prevail in a workably competitive market.

In the case before the Tribunal, the ACCC submitted that it was not reasonable for Optus to apply the stand-alone counterfactual when determining costs. The Tribunal disagreed with the ACCC as follows:[11]

> *'We consider that determining the costs of a stand-alone mobile operator, for the purpose of determining whether the price terms of the undertaking in relation to Optus' DGTAS are reasonable, is more consistent with the matters set out in s 152AH and the objectives in s 152AB than requiring Optus to take into account the cost consequences of it being an operator of a fixed-line network and a mobile network.* ***If the objective of regulating a particular industry is to replicate, as far as possible, the environment of a competitive market, then it is desirable to use as a benchmark criteria or principles which would exist in a competitive market, such as determining the costs of an operator operating in that market.***
>
> *Determining Optus' DGTAS costs as a stand-alone mobile operator would, all things being equal, be likely to result in the achievement of the objective of promoting competition in markets for listed services: s 152AB(2)(c). That is,* ***in competing with mobile operators who do not operate a fixed line network, Optus may gain a competitive advantage by having access to economies of scale and scope.*** *And Optus will not be at a disadvantage when it is competing against an integrated operator such as Telstra.*
>
> *Further, s 152AB(2)(e) requires us to have regard to the extent to which Optus' price is likely to result in the achievement of the objective of encouraging the economically efficient use of, and the economically efficient investment in, the infrastructure by which the listed services are supplied. In turn, in determining the achievement of this objective, s 152AB(6)(b) requires us to have regard to the legitimate commercial interests of Optus, including its ability to exploit economies of scale and scope. Determining Optus' DGTAS costs on a stand-alone mobile operator basis promotes these objectives.'* [Emphasis added]

[10] [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].
[11] [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [122]-[124].

The Tribunal's decision establishes that the benchmark against which the efficiency of CitiPower's expenditure under outsourcing arrangements should be assessed is that of stand-alone, in-house service provision.

Balancing the efficiency criterion and the prudency criterion

There is a tension between the efficiency and the prudency criteria that has been recognised by expert consultants for both the AER and DNSPs and was observed by the Tribunal in *Application of Energy Australia and Others*.[12] As a result, in applying the opex and capex criteria to a DNSP's expenditure forecasts and determining whether it is satisfied that those forecasts reasonably reflect the criteria, the AER must strike a reasonable balance between the efficiency and prudency criteria. However, the AER's discretion to balance the efficiency and prudency criteria is not unlimited.

CitiPower considers that, in striking a reasonable balance between the efficiency criterion and the prudency criterion, the AER has no discretion to reduce a DNSP's expenditure forecasts below *'the efficient costs of achieving the* operating expenditure objectives*'*. That is, the AER has no discretion to reduce a DNSP's expenditure forecasts below the expenditure that reasonably reflects the efficiency criterion.

The opex and capex criteria do not, of themselves, necessitate that the reasonable balance the AER strikes between the efficiency and prudency criteria must be at least the efficient costs of achieving the opex and capex objectives. However, in exercising its discretion to balance the efficiency and prudency criteria, the AER must exercise its discretion in a manner that is likely to contribute to the achievement of the NEO and take into account the revenue and pricing principles.[13] It is this obligation that necessitates that the balance the AER strikes between the efficiency and prudency criteria must be at least the efficient costs of achieving the relevant objectives.

In its decision in *Application of Energy Australia and Others* of 12 November 2009, the Tribunal concluded that the NEO *'provides the overarching economic objective for regulation under the NEL'*.[14] The Tribunal further observed that the revenue and pricing principles in section 7A of the NEL *'can be taken to be consistent with and to promote the objectives in s 7'* and that the principles *'are themselves stated normatively in the form of what is intended to be achieved'*.[15]

As discussed above, the revenue and pricing principles include, in particular, section 7A(2) which provides:

> *A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> *(a) providing direct control network services; and*

[12] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [140]-[142].
[13] NEL, section 16.
[14] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [14].
[15] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [74].

> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.'*

In *Application of Energy Australia and Others*, the Tribunal observed that *'[i]t is well accepted in the literature of regulatory economics and in regulatory practice that all these efficiency objectives [reflected in the NEO and the revenue and pricing principles] are in principle met by setting prices for services that allow the recovery of efficient costs'*.[16] It then gave specific consideration to construing section 7A(2) of the NEL as follows:[17]

> *'It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterised by various uncertainties, intervene between an ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, the dice are loaded against the NSP at the outset by the regulator not providing the opportunity for it to recover its efficient costs (eg, by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.*
>
> ***Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs.*** *This is in the context of no adjustment generally being made after the event for changed circumstances.' [Emphasis added]*

It follows that the AER has no discretion to reduce a DNSP's expenditure forecast below the efficient costs of achieving the relevant expenditure objectives, on the basis of its assessment of that expenditure forecast against the prudency criterion.

CitiPower's views on the AER's discretion to balance the efficiency and prudency criteria are also consistent with the opinions expressed by the AER's own expert, Wilson Cook, in the review culminating in the NSW Final Determination on the operation of the efficiency and prudency criteria and the resultant necessity for a balance to be struck. Wilson Cook, in its expert report for the AER of October 2008, contemplated that *'a prudent operator might undertake more work than otherwise considered necessary but to ensure efficiency it might undertake less and thus a balance between the two is required'*.[18] The Tribunal recognised these expert opinions as *'non-controversial'* in *Application of Energy Australia and Others*.[19]

[16] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [76].
[17] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [77] & [78].
[18] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [141].
[19] [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [142].

Confidential Appendix 5.2 - Analysis of CitiPower's Corporate Services Agreement with CHED Services and Network Services Agreement with PNS

CitiPower claims confidentiality over this Appendix 5.2 in its entirety.

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Appendix 6.1 – Step change - Electricity Safety (Electric Line Clearance) Regulations 2010

In this Appendix, CitiPower details its Revised Regulatory Proposal in respect of its proposed step changes for compliance with the 2010 Line Clearance Regulations and achieving compliance in LBRA.

Summary of key points

The 2010 Line Clearance Regulations will significantly increase CitiPower's costs of maintaining required vegetation clearances. This is because there are significant changes between the 2010 Line Clearance Regulations and the 2005 Line Clearance Regulations.

In its Draft Determination, the AER has fallen into error in seeking to estimate the step change cost for DNSPs of complying with the 2010 Line Clearance Regulations by reference to the cost benefit analysis in the Line Clearance RIS (by deducting the costs to DNSPs of complying with the 2005 Line Clearance Regulations estimated in the Line Clearance RIS from the estimated costs of complying with the 2010 Line Clearance Regulations). The AER cannot rely on the cost impact analysis in the Line Clearance RIS in determining the step change costs of complying with the 2010 Line Clearance Regulations. This is because the Line Clearance RIS failed both to correctly identify the key changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations, and to correctly cost compliance with the 2010 Line Clearance Regulations as compared with the 2005 Line Clearance Regulations.

CitiPower's vegetation clearance contractor, VEMCO has considered the cost impact of each of the changes between the 2010 Line Clearance Regulations and the 2005 Line Clearance Regulations based on legal advice on those changes provided by DLA Phillips Fox dated 21 June 2010. Since VEMCO is engaged by CitiPower to undertake vegetation clearance in accordance with the Regulations, these costs reflect the increased costs CitiPower will be required to pay if the 2010 Line Clearance Regulations come into effect. CitiPower submits that the AER should accept those step change costs as reasonably reflecting the opex criteria.

CitiPower omitted in its Initial Regulatory Proposal to identify the step change costs of its program of achieving compliance with the requirements of the 2005 Line Clearance Regulations and Code in respect of LBRA. Accordingly, that step change is included in this Revised Regulatory Proposal.

CitiPower's response to AER's Draft Determination

In its response to the AER's Draft Determination, below CitiPower:

- explains that the AER cannot rely on the cost impact analysis in the Line Clearance RIS in determining the step change costs of complying with the 2010 Line Clearance Regulations. This is because the Line Clearance RIS failed both to correctly identify the key changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations, and to correctly cost compliance with the 2010 Line Clearance Regulations as compared with the 2005 Line Clearance Regulations. As the AER is aware, ESV has expressly told the AER that it cannot rely on the cost impact analysis in the Line Clearance RIS for the purpose of determining the step changes in the price review process[1];

- describes the changed regulatory obligations resulting from the changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations and the step change costs resulting from those changes; and
- sets out the step change cost of achieving compliance in respect of LBRA.

CitiPower observes that the ESV has indicated to it that it may consider changes to the 2010 Line Clearance Regulations later in 2010. Since it is unclear when or if any changes will be made, the AER should accept CitiPower's proposed step changes in respect of the 2010 Line Clearance Regulations. If any changes are made to the 2010 Line Clearance Regulations any cost implications of those changes could be assessed by the AER through the pass through provisions.

Costs resulting from change in Regulations

The 2010 Line Clearance Regulations and Code came into operation on 29 June 2010 and will likely apply for five years.[2] Compliance with the 2010 Line Clearance Regulations will result in increased costs to CitiPower which are not reflected in CitiPower's 2009 base year opex.

The AER based its analysis of the step change cost of complying with the 2010 Line Clearance Regulations solely on the changes between the 2005 Line Clearance Regulations and 2010 Line Clearance Regulations identified in the Line Clearance RIS and sought to estimate the step change cost for DNSPs of complying with the 2010 Line Clearance Regulations by reference to the cost benefit analysis in the Line Clearance RIS.

The AER cannot obviate its duty to identify the regulatory changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations for the purpose of assessing the claimed step change by relying on the Line Clearance RIS or any view of the ESV. It must discharge its duty to identify those regulatory changes by performing its own assessment of the changes.[3] In *Application by Energy Australia* [2009][4] the Tribunal observed that the AER could not reject a DNSP's proposed opex forecast merely because it has an expert opinion. Rather, the Tribunal said the '*AER, based upon any expert advice, needs to make its own evaluation, an evaluation that is reviewable by the Tribunal.'* While this was said in the context of the AER's reliance on expert advice, the same principle that the AER must make its own evaluation applies.

CitiPower has obtained legal advice on the regulatory changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations.[5] That legal

[1] Meeting with the AER, ESV and Victorian DNSPs on 13 July 2010.

[2] Section 89 of the *Electricity Safety Act* 1998 (Vic) provides that there must always be regulations in force that prescribe a code of practice, but no such regulations shall continue in force for more than five years.

[3] In *Application by Energy Australia* [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal), at [190] the Tribunal observed that the AER could not reject a DNSP's proposed opex forecast merely because it has an expert opinion. Rather, the Tribunal said the '*AER, based upon any expert advice, needs to make its own evaluation, an evaluation that is reviewable by the Tribunal.'*

[4] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal), at [190]

[5] Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

advice identifies additional key changes to those identified and considered in the Line Clearance RIS.

In this Appendix to its Revised Regulatory Proposal, CitiPower

- shows that the Line Clearance RIS failed to correctly identify and assess all of the key changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations;
- shows that the Line Clearance RIS failed to properly cost the costs of complying with the 2010 Line Clearance Regulations; and
- sets out the step change costs that will be incurred by CitiPower in complying with the 2010 Line Clearance Regulations and explains why those cost estimates differ to those previously provided by CitiPower to the AER.

Line Clearance RIS failed to correctly identify key changes

As noted above, CitiPower’s legal advice on the regulatory changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations identifies additional key changes to those identified and considered in the Line Clearance RIS.

When compared to the Line Clearance RIS, the legal advice shows that the Line Clearance RIS failed to correctly identify and assess all of the key changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations.

Significantly the Line Clearance RIS:

- fails to recognise or assess the implications of the removal of clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Line Clearance Code from the 2010 Line Clearance Code;
- fails to recognise the requirement in Table 2 of the 2010 Line Clearance Code for larger clearance spaces for spans exceeding 100 metres than was required by Table 10.1 of the 2005 Line Clearance Code;
- does not properly interpret or assess the notification and consultation obligation under the 2010 Line Clearance Regulations;
- does not properly interpret or assess the new obligation in respect of native trees and environmentally significant trees; and
- fails to recognise or assess the implications of the removal of the exemption.

The key changes identified in the Line Clearance RIS were:[6]

- under the 2010 Line Clearance Regulations, only major electricity distributors will need to submit their management plans to ESV for approval; whereas under the 2005 Line Clearance Regulations, all responsible persons need to submit their management plans to ESV for approval;

[6] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p xviii, p60.

- the definition of environmentally or culturally significant trees is more specific and the 2010 Line Clearance Code restricts the cutting of these trees to the minimum extent necessary. Greater protection is given to areas of native trees, trees of ecological, historical or aesthetic significance or trees of cultural or environmental significance and vulnerable, endangered or critically endangered faunal species under the *Flora and Fauna Guarantee Act* 1988;
- responsible persons must notify by newspaper and consult rather than seek permission or notify in writing occupiers/owners of private land/affected persons before cutting or removing trees;
- under the 2010 Line Clearance Regulations, minimum clearance spaces surrounding aerial bundled cable or insulated cable will also apply to small tree branches; whereas under the 2005 Line Clearance Regulations these minimum clearance spaces do not apply under specified conditions;
- under the 2010 Line Clearance Regulations, minimum clearance spaces surrounding powerlines in HBRAs will also apply to tree branches above a powerline of 22,000 volts; whereas under the 2005 Line Clearance Regulations these minimum clearance spaces do not apply under specified conditions; and
- the penalty for a breach of proposed subregulation 9(4) is also increased under the 2010 Line Clearance Regulations from 10 penalty units to 20 penalty units.

Key changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations which have significant cost implications for DNSPs which the Line Clearance RIS failed to take into account were:

- the 2010 Line Clearance Regulations do not replicate the exemption granted to CitiPower and other Victorian distributors from compliance with requirements of the 2005 Line Clearance Code in LBRA and HBRA;
- the exception in clause 9.3 of the 2005 Line Clearance Code, which provided, in certain circumstances, for reduced clearing in relation to tree branches that exceed 130 millimetres in diameter, if the branch is more than 300 millimetres from an aerial bundled cable or insulated cable, has been omitted from the 2010 Line Clearance Code;
- the exceptions in clauses 10(b) and (c) of the 2005 Line Clearance Code which provided for smaller clearances than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts in LBRA where the responsible person complied with clause 12 of the 2005 Line Clearance Code have been omitted from the 2010 Line Clearance Code; and
- the requirement in Table 2 of the 2010 Line Clearance Code for larger clearance spaces for spans exceeding 100 metres than was required by Table 10.1 of the 2005 Line Clearance Code.

As a consequence, in some cases the Line Clearance RIS failed to correctly estimate the cost impact of the above changes. In other cases the Line Clearance RIS failed to estimate at all the cost impact of the change.

Line Clearance RIS failed to correctly cost key changes

The AER cannot rely on the estimates of the costs of complying with the 2010 Line Clearance Regulations in the Line Clearance RIS. Apart from the fact that the Line Clearance RIS failed to cost all significant changes between the 2010 Line Clearance Regulations and the 2005 Line Clearance Regulations, the RIS made errors in estimating the cost of those changes it did cost.

Subsequent to the Line Clearance RIS, CitiPower made a submission to the ESV which pointed out errors in the RIS, set out in detail the cost implications of the 2010 Line Clearance Regulations and recommended changes to the 2010 Line Clearance Regulations to reduce the amount of those costs.[7] The ESV did not make any of the changes to the 2010 Line Clearance Regulations recommended by CitiPower,[8] nor did the ESV correct any of the obvious errors in the Line Clearance RIS. Examples of how the estimates in the Line Clearance RIS are self-evidently flawed are:

- in estimating the cost of the notification and consultation obligation under the 2010 Line Clearance Regulations, the Line Clearance RIS focused solely on the notification requirement and omitted to consider the consultation requirement. Further, in estimating the cost of notification under the 2005 Line Clearance Regulations, the Line Clearance RIS used cost estimates for CitiPower which did not solely relate to notification;
- in estimating the cost of the omission in the 2010 Line Clearance Regulations of clauses 9.2.1 and 9.2.2 of the 2005 Line Clearance Regulations, the Line Clearance RIS only considers the cost impact in relation to overhead service cables; and
- the Line Clearance RIS fails to properly interpret or assess the new obligation in respect of native trees and environmentally significant trees.

These examples are expanded on below.

Notification and consultation

The notification requirements in the 2010 Line Clearance Regulations are concerned with giving notice to ‘affected persons’ (being owners or occupiers of adjacent land where the cutting or removal of the tree will affect the use of that land). The consultation requirements are concerned with consulting with owners and occupiers.

Clause 5(2) of the 2010 Line Clearance Regulations requires a responsible person to give notice to affected persons of cutting or removal of trees:

- where the tree is on public land;
- where the tree is within the boundary of a private property; and/or

[7] CitiPower, Response to the ESV’s Line Clearance RIS, 20 May 2010 (Attachment 242 to this Revised Regulatory Proposal).
[8] CitiPower, Response to the ESV’s Line Clearance RIS, 20 May 2010 (Attachment 242 to this Revised Regulatory Proposal).

- where the tree is of cultural or environmental significance.

Notice to affected persons must be in writing or by publication in a newspaper at least 14 days but not more than 60 days before the intended cutting or removal. Under the notice requirement in the 2005 Line Clearance Code there is no outer limit (60 day or otherwise) on when the cutting or removal must occur after notice is given.

In addition to these notification requirements, if the tree is within the boundary of a private property clause 5(5) of the 2010 Line Clearance Code requires a responsible person to **consult**:[9]

- in the case of a tree being cut, the occupier of the property on which the tree is to be cut; or
- in the case of a tree being removed, the owner of the property from which the tree is to be removed.

Accordingly, the 2010 Line Clearance Code provides for a different procedure for dealing with owners and occupiers in the event of removing or cutting a tree from the procedure for dealing with affected persons.

There is an error in assessing the cost impact of clause 5 of the 2010 Line Clearance Code in the Line Clearance RIS. The Line Clearance RIS only took into account the cost of giving **notice** to affected persons under clause 5(2) and failed to consider the cost of consulting with owners or occupiers required by clause 5(5). As explained below, having regard to the requirement to consult with owners or occupiers, in practice, the 2010 Line Clearance Regulations will result in a slight decrease in consultation and notification costs for CitiPower.

The Line Clearance RIS noted that clause 5 of the 2010 Line Clearance Code allows responsible persons to notify affected persons via a newspaper advertisement and not as a last resort as in the 2005 Line Clearance Code. The Line Clearance RIS stated that *'[t]his will provide a much more cost effective alternative for electricity distribution businesses'*.[10] It then provided estimates of the cost of complying with the notification requirement by multiplying the cost of an advertisement by an assumed number of notices per annum for each distribution business.[11] By focusing solely on the requirement to notify affected persons, the Line Clearance RIS estimated that the change in the notification and consultation requirements from the 2005 Line Clearance Regulations would result in cost savings. According to the Line Clearance RIS the cost savings to CitiPower from the change between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations are ($3,146-$450,000) x 5 years) [12]]

[9] Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

[10] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p9.

[11] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p9, 140.

[12] The Line Clearance RIS estimates the cost of notification under the 2010 Line Clearance Regulations to be $3,146 for CitiPower and under the 2005 Line Clearance Regulations to be $450,000 (p137 and 140 of the Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal). Therefore, according to the Line Clearance RIS, the cost impact of the change from the 2005 Line Clearance Regulations to the 2010 Line Clearance Regulations is a saving of $2,234,270 for CitiPower over 5 years.

In making this statement and in calculating the costs of consultation under clause 5 of the 2010 Line Clearance Code, the Line Clearance RIS focused solely on the notification requirement in respect of affected persons. The Line Clearance RIS ignored the requirement in clause 5(5) of the 2010 Line Clearance Code to consult owners and occupiers of properties where trees are cut or removed.

CitiPower considers that compliance with the requirement to consult with owners and occupiers requires more than merely publishing a notice of the removal or cutting of trees in a newspaper.

Based on the legal advice it has received,[13] CitiPower's understanding of the meaning of consult in clause 5(5) is that it requires:

1. CitiPower to give notice in writing to the occupier (where a tree is to be cut) or owner (where a tree is to be removed) of the intended cutting or removal of the tree. The notice must identify the tree to be cut or removed and the timing of that cutting/removal in order that the notice can facilitate consultation.
2. In the notice, CitiPower should invite any objections from the occupier of the property (where the tree is to be cut) or owner of the property (where the tree is to be removed). Notice should be in writing and delivered to the letterbox of the occupier or owner rather than merely by publication in a newspaper, in order that the notice can contain information of sufficient specificity to facilitate consultation with the owner or occupier.
3. If the owner or occupier does raise an objection, CitiPower is required to genuinely consider the objection. However, CitiPower is not required to attempt to reach agreement with the owner or occupier on the removal/cutting. Further, provided CitiPower considers the objection, it is not necessary for CitiPower to resolve the objection in favour of the owner/occupier raising the objection.

Further, in estimating the cost of notification under the 2005 Line Clearance Regulations, the Line Clearance RIS used cost estimates for CitiPower which did not solely relate to notification. The Line Clearance RIS purported to use a cost estimate provided to it by CitiPower of $450,000.[14] However, the cost estimate that CitiPower provided to ESV was $550,000.

Significantly, this cost estimate did not just comprise negotiation and consultation costs. It also included costs for management, IT and data management, inspection (including field officers, contractor management and data capture) and auditing. This is because CitiPower’s vegetation management systems and processes link the inspection process with the notification and consultation process. ESV was informed of the different components of CitiPower’s cost estimate in December 2009. A breakdown of those costs is provided in the following table:

[13] Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).
[14] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p137.

Activity	Cost
Notification, consultation and negotiation	$30,000
Management, IT & data management	$120,000
Inspection, workload identification, contractor management and data capture	$360,000
Auditing	$40,000
Total	**$550,000**

Table A6.1.1 Breakdown of costs provided by CitiPower to ESV

In its Draft Determination, the AER calculated CitiPower's step change cost of complying with the notification requirements of the 2010 Line Clearance Code as -$446,000.[15] This is because the AER calculated the step change as the difference between the cost of complying with the notification requirements under the 2005 Line Clearance Code set out the Line Clearance RIS (ie. $450,000) and the cost of complying with the notification requirements in the 2010 Line Clearance Code set out in the Line Clearance RIS (ie. $4,000). The AER incorrectly concluded that the cost estimate in the Line Clearance RIS for CitiPower was based on SP AusNet's cost estimate. In fact, it was purportedly based on the cost provided by CitiPower on behalf of CitiPower, albeit that the Line Clearance RIS misstated that cost estimate.[16]

As set out above, the component of the cost estimate of complying with the 2005 Line Clearance Code relevant to notification and consultation for CitiPower is in fact $30,000. Further, the cost estimate in the Line Clearance RIS for complying with the 2010 Line Clearance Code fails to take into account the cost of consultation and accordingly must be higher than $4,000.

As such the AER will be in error if it relies on the cost estimates in the Line Clearance RIS in calculating this step change.

Omission of exceptions in clauses 9.2.1 and 9.2.2 of the 2005 Line Clearance Code

Clause 10 of the 2010 Line Clearance Code establishes the clearance space requirements for aerial bundled cables and insulated cables in all areas. The equivalent clause of the 2005 Line Clearance Code is clause 9.

Clauses 9.2.1 and 9.2.2 of the 2005 Line Clearance Code have been omitted in the 2010 Line Clearance Code. These clauses exempt small branches and leaves from the minimum clearance space requirement under certain circumstances. Clause 9.3 of the 2005 Line Clearance Code has also been omitted. This provides that if a responsible person complies with clause 12 of the 2005 Line Clearance Code, the requirements of clause 9.1 would not apply to existing tree branches that

[15] AER, Draft Determination, Appendix L, p163.
[16] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p137, footnote 311.

exceed 130 millimetres in diameter, if the branch is more than 300 millimetres from an aerial bundled cable or insulated cable.

In the case of CitiPower, the Line Clearance RIS sets out a cost increase from the omission of clauses 9.2.1 and 9.2.2 of $$3,109,968 over 5 years.[17] However, it only captures the cost impact in relation to overhead service cables – that is, the service lines from the pole to the building. The ESV failed to take into account the cost impact of this change on circuit cables – that is, the lines from pole to pole running down the street. Since the relevant clauses relate to all aerial and insulated cables, the ESV should have costed the compliance requirements taking into account all aerial and insulated cables, not just the cost impact for overhead service cables.

Further, the Line Clearance RIS incorrectly only considered the initial establishment cost (being the initial cost of meeting the requirements of the 2010 Line Clearance Code). It stated that the omission of these clauses would not force a change in annual maintenance costs – that is, it does not change the normal cutting cycle. Contrary to the Line Clearance RIS the omission of clauses 9.2.1 and 9.2.2 will result in increased annual costs in maintaining the clearance space once it has been established. In order to comply with the 2010 Line Clearance Code CitiPower will need to re-inspect, notify customers and clear each span annually.

The cost estimate in the Line Clearance RIS was based upon figures provided by SP AustNet. However, in SP AusNet's response to the Line Clearance RIS dated 10 May 2010, consistent with CitiPower's position, SP AusNet informed ESV that it had misapplied its cost estimate because ESV had chosen to include only the initial cost for establishing the clearance space and incorrectly determined that there would be no on-going cost to maintain the clearance space. SP AusNet stated in respect of the costs of omitting clauses 9.2.1 and 9.2.2: [18]

> '*ESV's assumption of an initial establishment cost only, is incorrect. Maintenance of the proposed clearance space is a new obligation and will logically require continual pruning to maintain compliance, similar to the requirements for bare powerlines. This is additional work to that already undertaken within current pruning cycles. The estimates and methodology SP AusNet provided to ESV were for incremental costs. These were derived by calculating the cost of maintaining a clearance space, in accordance with the removal of clauses 9.2.1 and 9.2.2, less the current cost for compliance which only requires prevention of abrasive damage.*
>
> ***Note:*** *Typically, a clearance space created within the structure of vegetation encourages re-growth to void with increased vigour.*
>
> *SP AusNet's assessed incremental cost, as previously provided, is $34M or* ***PV $27.1M*** *over five years. The RIS included only a PV of $5.4 over five years establishment cost. By applying the same factor that ESV has reduced SP AusNet's advised costs to the costs in table A3.16* [of the RIS] *and the*

[17] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p146.

[18] Letter from SP Austnet to ESV dated 10 May 2010 regarding Proposed Electricity Safety (Electric Line Clearance) Regulations 2010 – Regulatory Impact Statement, pp19-20 (Attachment 247 to this Revised Regulatory Proposal).

*five year cost of $14.99M in Section 3.5.3 indicates a total five year PV cost of approximately **$172.9M**.*'

As set out below CitiPower will experience a far greater cost impact than determined by the Line Clearance RIS as a result of the omission of current clauses 9.2.1 and 9.2.2.

Native trees

Clause 2(3) of the 2010 Line Clearance Code contains a new requirement that a responsible person must, as far as practicable, restrict cutting or removal of native trees or trees of cultural or environmental significance to the minimum extent necessary to ensure compliance with that Code.

There is no protection given to native trees under the 2005 Line Clearance Code. Further, the 2005 Line Clearance Code does not require a responsible person to minimise cutting or removal of trees of cultural or environmental significance, but rather requires that a responsible person cannot cut or remove vegetation of that kind without first obtaining advice from a qualified arborist or horticulturalist.

Approximately 90 per cent of vegetation cleared by CitiPower in Victoria would be classified as ‘native’. Should CitiPower only be allowed to cut to minimum clearance spaces, this would in turn significantly increase annual maintenance costs by reducing the period between pruning cycles thus increasing the frequency of cutting across the network.

The Line Clearance RIS states that proposed clause 2(3) requires a person to, as far as practicable, minimise cutting of particular vegetation.[19] It states that 'practicable' is defined under the Electricity Safety Act and includes consideration of both the magnitude of hazards and costs of dealing with those hazards. Accordingly, the Line Clearance RIS states that proposed clause 2(3) allows a responsible person to come to a reasonable balance between the extent of cutting and the length of time between cutting cycles and does not force a responsible person to change long established, reasonable cutting cycles.

It was on this basis that the Line Clearance RIS considered that clause 2(3) did not impose additional costs.[20] However, the wording of clause 2(3) does not reflect the comments made in the Line Clearance RIS. That is, clause 2(3) does not state that there is no need for DNSPs to change long established cutting cycles. The meaning of ‘practicable’ in the 2010 Line Clearance Code is unclear. In its Response to the Line Clearance RIS CitiPower submitted that a definition of 'practicable' should be inserted into the 2010 Line Clearance Code to clarify that the cost of removing the vegetation is relevant to what is practicable under clause 2(3), and that clause 2(3) should be amended to make clear that ‘practicable’ is what is practicable in the opinion of the responsible person. However, none of these recommendations were implemented by the ESV in finalising the 2010 Line Clearance Code.

Accordingly, in order to comply with clause 2(3) CitiPower will be required to increase the frequency of pruning across its entire vegetation management program. This is due to CitiPower’s inability to clear lower growing native vegetation from under powerlines in early stages of growth because these trees are

[19] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p 126.
[20] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p125.

outside the minimum clearance space. CitiPower will only be able to action these trees once they enter the minimum clearance space.

Contrary to what is stated in the Line Clearance RIS, this will significantly increase CitiPower's costs of complying with the 2010 Line Clearance Regulations.

Conclusion

It is clear from the above examples that the AER cannot rely on the cost assessments in the Line Clearance RIS in determining the step change costs as a result of the 2010 Line Clearance Regulations. Rather, the AER should identify the differences between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations and assess whether it can be satisfied that CitiPower's step change costs for those differences reasonably reflect the opex criteria on the basis of the evidentiary material before it. For the reasons explained below CitiPower asserts that the AER can be satisfied that CitiPower's step change costs reasonably reflect the opex criteria.

CitiPower's step change costs

The following section of this Appendix describes CitiPower's proposed step change costs for complying with the 2010 Line Clearance Regulations.

The costs were obtained from CitiPower's vegetation clearance contractor, VEMCO.[21] CitiPower received legal advice on the changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations from DLA Phillips Fox dated 21 June 2010.[22] CitiPower provided the legal advice to VEMCO and asked VEMCO to advise it of the cost impact of those changes.[23] VEMCO provided a letter dated 13 July 2010 to CitiPower in respect of the cost increases above 2009 actual costs that will apply over the years from January 2011 to December 2015.[24] Since VEMCO is engaged by CitiPower to undertake vegetation clearance in accordance with the 2010 Line Clearance Regulations, these costs reflect the increased costs CitiPower will be required to pay now that the 2010 Line Clearance Regulations have come into effect.

CitiPower notes that these costs differ from the cost estimates provided by CitiPower to the AER on 4 March 2010. Since that time, as noted above CitiPower has received the legal advice on the changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations from DLA Phillips Fox dated 21 June 2010. In addition, CitiPower asked its service provider VEMCO to calculate the cost impact of those changes, having regard to that legal advice.[25] As a result, CitiPower's understanding of the cost implications of the

[21] Letter from VEMCO to CitiPower and Powercor Australia dated 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal). Note that CitiPower has not proposed a step change for item 5 of VEMCO's letter .

[22] Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

[23] Note that VEMCO's estimates of the cost of complying with the 2010 Line Clearance Regulations have changed slightly from those provided by CitiPower in its Response to the Line Clearance RIS (Attachment 242 to this Revised Regulatory Proposal) following further detailed consideration of the impact of the 2010 Line Clearance Regulations.

[24] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

[25] Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

2010 Line Clearance Regulations has markedly increased since it provided cost estimates to the AER on 4 March 2010.

The following section of this Appendix describes the step change costs of each of the key changes.

The changes identified by VEMCO as having the major cost impacts for CitiPower are:

- the omission of clauses 9.2.1, 9.2.2 and 9.3 of the 2005 Line Clearance Code which excepted small branches and leaves from the clearance space requirement for aerial bundled and insulated cables in certain circumstances;
- the omission of clauses 10(b) and 10(c) of the 2005 Line Clearance Code which allowed for smaller clearance space requirements than would otherwise apply for powerlines of 22,000 volts or less and 66,000 volt powerlines in LBRA in certain circumstances;
- changes to the notification and consultation requirements; and
- the new restrictions on the cutting and removal of native trees and trees of cultural or environmental significance; and

Omission of exceptions in Clauses 9.2.1, 9.2.2 and 9.3 of 2005 Line Clearance Code

As noted above, clause 10 of the 2010 Line Clearance Code establishes the clearance space requirements for aerial bundled cables and insulated cables in all areas. The equivalent clause of the 2005 Line Clearance Code is clause 9.

Clauses 9.2.1 and 9.2.2 of the 2005 Line Clearance Code have been omitted in the 2010 Line Clearance Code. These clauses exempt small branches and leaves from the minimum clearance space requirement under certain circumstances. Specifically, the clauses provided that:

- *'clause 9.2.1 - the requirement for clearance space surrounding an aerial bundled cable or insulated cable under clause 9.1 does not apply to small tree branches with a diameter of less than 10 millimetres and leaves if, at least once a year, the branches and leaves are removed from the clearance space as required in clause 9.1; and*
- *clause 9.2.2 – branches and leaves are not required to be annually removed in accordance with clause 9.2.1 if the branches and leaves are not likely to abrade the cable before they are next removed in accordance with this Code.'*

The cost impact of this change is high because VEMCO will have to first establish the required clearances around all service lines and aerial bundled cable conductors (not just overhead service cables as incorrectly scoped in the Line Clearance RIS) and then maintain these clearances at all times. It is likely that most aerial bundled and insulated cables will have vegetation adjacent to them. Accordingly, this change will require all of those spans to have a new clearance space created to allow for re-growth. Once this space has been established, VEMCO will need to reinspect, notify customers and clear each span annually.

Further, most of the aerial bundled and insulated cables have been erected in areas where customers are sensitive to the clearing of trees. CitiPower faces serious customer complaints in those areas and is therefore limited in terms of how much it can cut during each cutting cycle. As a result, compliance with this provision will be costly.

As noted above, the Line Clearance RIS incorrectly costed the impact of the omission of clauses 9.2.1 and 9.2.2. It only captured the cost impact in relation to overhead service cables and failed to take into account the cost implications with respect to all aerial and insulated cables.[26]

Clause 9.3 of the 2005 Line Clearance Code provided an exception from the clearance space requirements for powerlines constructed with aerial bundled cable or insulated cable in clause 9.1 for existing tree branches that exceeded 130 millimetres in diameter, if the branch is more than 300 millimetres from an aerial bundled cable or insulated cable, where the responsible person complied with clause 12 of the 2005 Line Clearance Code. Clause 12 of the 2005 Line Clearance Code provided that the clause 9.3 exemption to clause 9.1 applied where the distribution company ensured that an arborist carried out an annual risk assessment on the tree and kept records of that assessment for a period of no less than 5 years.

CitiPower took advantage of the exception; as a consequence the removal of clause 9.3 will have a cost impact. In complying with the omission of clauses 9.2.1 and 9.2.2, CitiPower can achieve compliance with the omission of the exception in clause 9.3.

VEMCO advised CitiPower that the following cost increases above 2009 actual costs will apply over the years from January 2011 to December 2015 to comply with clause 10 of the 2010 Line Clearance Code as a result of the removal of the exceptions in clauses 9.1, 9.2 and 9.3 of the 2005 Line Clearance Code.[27]

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – lines from pole to pole	309	309	309	309	309	**1,545**
Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – service lines from pole to building	2,712	2,712	2,712	2,712	2,712	**13,558**

Table A6.1.2 Omission of exceptions in clauses 9.2.1, 9.2.2 and 9.3 step change costs

[26] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p146.

[27] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

Omission of exceptions in Clauses 10(b) and (c) of the 2005 Line Clearance Code

Clause 11 of the 2010 Line Clearance Code establishes the clearance space requirements for powerlines other than aerial bundled cable or insulated cables in LBRA. The equivalent clause of the 2005 Line Clearance Code is clause 10.

Clauses 10(b) and (c) as well as Tables 10.2 and 10.3 of the 2005 Line Clearance Code have been omitted from the 2010 Line Clearance Regulations. These clauses provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Line Clearance Code.

CitiPower had been complying with clause 12 of the 2005 Line Clearance Code. The removal of the option of reduced clearances in LBRA for bare powerlines will result in a significant increase in expenditure. There will be a number of spans which will widen clearances in accordance with the 2010 Line Clearance Regulations. These spans will all need to be cleared to the new increased clearance space requirements.

The Line Clearance RIS failed to estimate the cost of omitting clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Line Clearance Code.

VEMCO advised CitiPower that the following cost increases above 2009 actual costs will apply over the years from January 2011 to December 2015 to comply with clause 11 of the 2010 Line Clearance Code as a result of the removal of the exceptions in clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Line Clearance Code. [28]

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Vegetation Clearance (omission of clauses 10(b) and (c) and Tables 10.2 and 10.3)	990	594	594	594	594	**3,366**

Table A6.1.3 Omission of clauses 10(b) and (c) and Tables 10.2 and 10.3 step change costs

Changes to Notification and Consultation Requirements

The changes to the notification and consultation requirements between the 2005 Line Clearance Code and 2010 Line Clearance Code are described above.

VEMCO has reviewed DLA Phillips Fox's legal advice dated 21 June 2010[29] and based upon its notification and consultation processes, it has calculated the step change cost of complying with the notification and consultation requirements under the 2010 Line Clearance Code. [30]

Based on VEMCO's notification and consultation processes, there is not a major difference between the requirements of the 2005 Line Clearance Code and the

[28] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).
[29] Attachment 244 to this Revised Regulatory Proposal.
[30] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

2010 Line Clearance Code. This is because the main difference for VEMCO's processes is that it no longer has to consult or negotiate agreements with 'affected persons', but rather is only required to notify affected persons and this can be achieved via newspaper advertisements. Under the 2010 Line Clearance Code VEMCO is still required to consult with private land owners and occupiers.

Currently notification and consultation with affected persons comprises only 1 per cent of VEMCOs notifications and consultations, with the remaining 99 per cent of notifications and consultations being with owners/occupiers. While under the 2010 Line Clearance Code there is an ability to notify affected persons via newspaper advertisements, this would actually be more expensive than notifying those persons by dropping written notices in their letterboxes.

VEMCO expects that any cost savings from the change to the Code will likely result in increased dispute resolution costs. This is because under the 2005 Line Clearance Code VEMCO was required to take reasonable steps to negotiate agreements with occupiers and affected persons where the cutting would change the established practice for that location. As such, VEMCO would generally follow up its notices of cutting with telephone calls to the occupiers and affected persons to ensure there were no objections. However, under the 2010 Line Clearance Code there is no requirement to reach agreement, accordingly, there is a risk that if in satisfaction of the requirement to consult, VEMCO sends a letter informing the occupier of the intended cutting and asking for any objections but does not follow up to ensure that there are no objections, this may result in a dispute with the occupier if VEMCO proceeds with the cutting and the occupier is in fact not happy about the cutting.

VEMCO has advised CitiPower that the changes between the notification and consultation requirements under the 2005 Line Clearance Code and 2010 Line Clearance Code will result in the following step change. [31]

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Vegetation Clearance (notification and consultation)	(1)	(1)	(1)	(1)	(1)	**(5)**

Table A6.1.4 Notification and consultation step change costs

Native trees

As set out above, clause 2(3) of the 2010 Line Clearance Code contains a new requirement that a responsible person must, as far as practicable, restrict cutting or removal of native trees or trees of cultural or environmental significance to the minimum extent necessary to ensure compliance with the 2010 Line Clearance Code.

There is no protection given to native trees under the 2005 Line Clearance Code. Further, the 2005 Line Clearance Code does not require a responsible person to

[31] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

minimise cutting or removal of trees of cultural or environmental significance, but rather requires that a responsible person cannot cut or remove vegetation of that kind without first obtaining advice from a qualified arborist or horticulturalist.

Approximately 90 per cent of vegetation cleared by CitiPower in Victoria would be classified as ‘native’. Should CitiPower only be allowed to cut to minimum clearance spaces, as the 2010 Line Clearance Code seems to require, this would in turn significantly increase annual maintenance costs by reducing the period between pruning cycles thus increasing the frequency of cutting across the network.

As described above, the Line Clearance RIS incorrectly concluded that clause 2(3) of the 2010 Line Clearance Code would not impose additional costs.[32]

VEMCO advised CitiPower that the following cost increases above 2009 actual costs will apply over the years from January 2011 to December 2015 to comply with clause 2(3) of the 2010 Line Clearance Code. [33]

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Vegetation Clearance (clause 2(3))	0	18	46	92	123	**280**

Table A6.1.5 Protection of native trees step change costs

LBRA Compliance

As noted above, CitiPower omitted in its Initial Regulatory Proposal to identify the step change the step change costs of complying with the requirements of the 2005 Line Clearance Regulations and 2005 Line Clearance Code in respect of LBRA.

Background to LBRA costs

A chronology setting out CitiPower’s compliance with the Regulations and Code in LBRA is provided at the end of this Appendix.

The chronology notes that ESV's attitude of compliance with the 2005 Line Clearance Regulations and 2005 Line Clearance Code prior to and during the review process that culminated in the ESCV's 2006-10 EDPR was that it only intended to enforce literal compliance with the 2005 Line Clearance Regulations as to the clearance between electric lines and vegetation during the Proclaimed Fire Declaration Period. Accordingly, in the ESCV's 2006-10 EDPR it determined that a reasonable allowance for the costs of complying with those Regulations was based on literal compliance with the 2005 Line Clearance Regulations during Proclaimed Fire Declaration Periods.

[32] ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p125.

[33] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

In November 2005, CitiPower brought an appeal from the ESCV's 2006-10 EDPR. The appeals were adjourned in December 2005 when the ESV informed the ESCV Appeal Panel that it proposed to grant exemptions to CitiPower from compliance with the 2005 Line Clearance Code. The appeals resumed in January 2006 at which time CitiPower indicated that the exemptions granted by ESV largely aligned what was required for high voltage wires in LBRA with its practical compliance regime. However, it was not satisfied that the exemption granted aligned with its practical compliance regime for low voltage wires in LBRA.

The ESCV Appeal Panel determined that CitiPower's desire to move from practical compliance to literal compliance with the 2005 Line Clearance Regulations for LBRA did not constitute a step change.[34] The ESCV Appeal Panel incorrectly based its consideration of what constitutes a step change on the ESCV's description of a step change in its 2006-10 EDPR. The ESCV described a step change as an adjustment to the base opex for costs arising from new or changed functions and legislative obligations (whether imposed by legislation or another regulatory instrument, for example, a licence, code or price determination). The ESCV Appeal Panel said:[35]

> *'Having regard to the manner in which the Determination describes the concept of a step change, the Panel is of the view that the 2005 Vegetation Regulations, which very closely match both the 1999 Vegetation Regulations and the 2004 Interim Vegetation Regulations, do not meet the criteria for a step change as they do not effectively impose new or changed regulatory obligations on electricity distributors. The definition of a step change also covers new or changed functions, but a desire on the part of the Appellant to move from practical compliance with Vegetation Regulations to literal compliance does not, in the view of the Panel, constitute a new or changed function.'*

In coming to this conclusion, the ESCV Appeal Panel incorrectly found that ESV would not change its enforcement activities with respect to vegetation clearance in the 2006-10 regulatory control period.[36] It is clear from the chronology that ESV did in fact change its enforcement activities during the 2006-10 regulatory control period to require literal compliance with the 2005 Line Clearance Regulation and exemption.

The chronology shows that from 2006-08 CitiPower undertook a detailed inspection of LBRA areas to quantify the workload required to comply with the 2005 Line Clearance Regulations. This assessment was agreed between ESV and CitiPower as necessary to quantify the extent of non-compliance. In September 2008 CitiPower presented to ESV a staged process to achieve compliance by 2014. This was reflected in the 2009-10 Vegetation Management Plan submitted to the ESV in February 2009. By letter dated 7 May 2009 ESV informed CitiPower that it was not in a position to approve the Vegetation Management

[34] ESCV Appeal Panel, ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal), paragraphs 25 and 26.
[35] ESCV Appeal Panel, ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal), paragraphs 25.
[36] ESCV Appeal Panel, ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal), paragraph 28.

Plan as it did not satisfy the requirements of the Electricity Safety Act and the 2005 Line Clearance Regulations. The approval criterion not met was the Vegetation Management Plan's staged approach to achieving compliance with the 2005 Line Clearance Code requirements for LBRA by the end of 2014.

CitiPower informed the ESV that it would be possible to achieve compliance by the end of 2012 but this would result in additional customer complaints due to the extensive cutting required. This would involve commencing the 3 year cutting cycle in July 2009 cutting for both clearance and regrowth. This cycle would allow six months at the end of the cycle to revisit vegetation cut prior to 1 July 2009 to the two year cycle of clearance only.

LBRA step change

As explained above, the 2006-10 opex forecast in ESCV's 2006-10 EDPR did not include the cost of achieving compliance in LBRA with the exemption.[37] Accordingly, CitiPower was not given an allowance in respect of those costs in the ESCV's 2006-10 EDPR.

The largest step up in costs as a result of increased inspection and cutting cycle costs will be incurred in 2009. Accordingly, these costs are reflected in CitiPower's base year opex. However, there will still be additional costs during the 2011-2015 regulatory control period associated with achieving full compliance above those reflected in CitiPower's base year opex.

Achieving compliance with the 2005 Line Clearance Regulations and 2005 Line Clearance Code in LBRA requires an increase in inspection frequency and an increase in the number of spans to be cleared (to increased clearances) to achieve compliance by the end of 2012. Once compliance has been achieved, the maintenance cycles will still require more frequent inspections and more spans to be cleared (to increased clearances), however, the work will be less than during 2011 and 2012.

The following table shows the difference between CitiPower's compliance policy in 2005 and the compliance policy which it has sought to implement since 2005:

Pre 2006	Post 2006
A risk based inspection and clearing program was undertaken. Current year clearance codes were inspected and any non-compliant spans were actioned in accordance with compliance targets. As part of the inspection, in addition to service requisitions and general audits a high percentage of other spans were audited and any obvious non-conforming spans were assessed and actioned in accordance with compliance targets. Those compliance targets were: • Spans assigned code 55: o surrounding 66kV powerlines lines actioned within 24 hours;	Inspection is undertaken for vegetation surrounding high voltage powerlines every 2 years and for vegetation surrounding low voltage powerlines every 3 years. It is intended that by 2012 the LBRA network will be compliant. Beyond 2012 the inspection cycles will continue and will include additional inspections of spans coded as current year. Any non-compliant spans will be actioned in line with the revised rectification targets of 18 weeks for code 56 and 48 hours for code 55.

[37] ESCV 2006-10 EDPR (Attachment 31 to this Revised Regulatory Proposal), pp223-24.

- surrounding 22kV powerlines actioned within 28 days; - surrounding low voltage powerlines actioned within 6 months. • Spans assigned code 56: - surrounding 66kV powerlines lines actioned within 4 months; - surrounding 22kV and low voltage powerlines actioned within 12 months.	

Table A6.1.6 Changes to compliance with clearance spaces in LBRA

It is highly likely that the ESV will continue its enforcement approach of requiring literal compliance with the Line Clearance Regulations and Line Clearance Code during the 2011-15 regulatory control period. Accordingly, the AER should accept CitiPower's costs of achieving full compliance with the Line Clearance Regulations and Line Clearance Code during that period.

VEMCO has advised CitiPower that the following costs above 2009 actual costs will apply during the period January 2011 to the end of December 2015 in respect of CitiPower's program of achieving compliance with the clearance space requirements in LBRA.[38]

	$'000 ($2010)					
	2011	2012	2013	2014	2015	Total
Vegetation Clearance (LBRA)	165	91	32	(3)	165	**450**

Table A6.1.7 LBRA step change costs

The total costs of complying with the 2005 Line Clearance Regulations and 2005 Line Clearance Code were forecast by determining the spans that will require additional inspection/pruning in LBRA as a result of compliance and the cost per span provided by CitiPower's vegetation management services contractor, VEMCO. The total costs were then compared to the costs associated with the program commenced in 2009 to achieve literal compliance by 2012 that are reflected in CitiPower's base year opex to determine the step change set out above.

In addition to the costs of achieving compliance with the 2005 Line Clearance Regulations and the 2005 Line Clearance Code in LBRA, in order to be compliant with the 2010 Line Clearance Code in LBRA CitiPower will incur increased vegetation clearance costs in LBRA as set out above as a result of the omission of the exceptions in clauses 9.2.1, 9.2.2, 9.3, 10(b) and 10(c) of the 2005 Line Clearance Code. The step change costs described in this section of the Appendix do not include those costs which are set out under the relevant headings above.

[38] Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

CitiPower's Revised Regulatory Proposal

CitiPower has revised its Initial Regulatory Proposal to include the following step change costs in respect of the 2010 Line Clearance Regulations and 2010 Line Clearance Code and in respect of achieving compliance in LBRA.

	$'000 ($2010)					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – lines from pole to pole	309	309	309	309	309	**1,545**
Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – service lines from pole to building	2,712	2,712	2,712	2,712	2,712	**13,558**
Vegetation Clearance (omission of clauses 10(b) and (c) and Tables 10.2 and 10.3)	990	594	594	594	594	**3,366**
Vegetation Clearance (notification and consultation)	(1)	(1)	(1)	(1)	(1)	**(5)**
Vegetation Clearance (clause 2(3) native trees)	0	18	46	92	123	**280**
Vegetation Clearance (LBRA)	165	91	32	(3)	165	**450**
Total Vegetation Clearance Step Change	**4,175**	**3,723**	**3,692**	**3,703**	**3,902**	**19,194**

Table 6.8 Step changes – Electricity Safety (Electric Line Clearance) Regulations

CHRONOLOGY OF VEGETETATION MANGEMENT COMPLIANCE

The following is a joint chronology for CitiPower and Powercor Australia.

Date	Event	Description
15/07/05	Letter from Ken Gardner, Chief Electrical Inspector Office of Chief Electrical inspector to Garry Audley CitiPower Pty[39]	Informs CitiPower that the 2005 Line Clearance Regulations are unchanged with regard to the industry practice of practical compliance rather than literal compliance at all times on the clearance space between electric lines and vegetation. The Office of Chief Electrical Inspector will not change its present interpretation or enforcement actions, but will continue to ensure that literal compliance occurs during the proclaimed Fire Declaration Period for the area.
12/10/05	ESCV's 2006-10 EDPR	ESCV decided that given ESV had indicated that it only intends to enforce literal compliance with the requirements imposed by 2005 Line Clearance Regulations as to the clearance between electric lines and vegetation during the Proclaimed Fire Declaration Period, a reasonable allowance for the costs of complying with those Regulations is one that is based on literal compliance with the 2005 Line Clearance Regulations during the Proclaimed Fire Declaration Periods.
9/11/05	CitiPower/Powercor Australia lodged notices of appeal from ESCV's 2006-10 EDPR	Ground 1 of the Appeal was that the ESCV incorrectly calculated the revenue requirement for CitiPower/Powercor Australia by concluding that it was reasonable to exclude the cost required to maintain compliance with and/or not necessary to make allowance for, or to include, the full costs of compliance with the 2005 Line Clearance Regulations.
14/12/05	Letter from Ken Gardner Director of ESV to Paul Fearon Chief Executive Officer ESCV[40]	Informs ESCV that ESV will grant an exemption from clause 2.1 of the 2005 Line Clearance Code in the Schedule to the 2005 Line Clearance Regulations. The exemption will be along the lines that: *'A responsible person which has a Management Plan under Regulation 9 of the Electricity Safety (Electric Line Clearance) Regulations 2005 that has been approved by the Office and which outlines the program ensuring compliance with section 2.1 of the Code of Practice for Electric Line Clearance during the period 1 December to 30 March each year is exempt from the requirement to maintain the clearance space for the rest of the year.'*
14/12/05	Appeals to ESCV Appeal Panel from the ESCV's 2006-10 EDPR adjourned	The appeals to the ESCV Appeal Panel from the ESCV's 2006-10 EDPR were adjourned when the ESCV produced a letter of 14/12/05 from the ESV to the ESCV regarding the exemptions.
21/12/05	Exemptions come into effect	Exemptions granted to CitiPower/Powercor Australia from clause 2.1 of the 2005 Line Clearance Code in respect of HBRA and LBRA come into effect. Exemptions provide that: • For HBRA CitiPower/Powercor Australia is exempted from the requirement to maintain the clearance space in accordance with clause 2.1 of the 2005 Line Clearance Code provided that it achieves the minimum clearance space requirements during the declared fire

[39] Attachment 248 to this Revised Regulatory Proposal.
[40] Attachment 248 to this Revised Regulatory Proposal.

Date	Event	Description
		danger period or the period 15 December to 31 March where there is no declared fire danger period. • For high voltage lines in LBRA, CitiPower/Powercor Australia is exempted from the requirement to maintain the clearance space in accordance with clause 2.1 of the 2005 Line Clearance Code provided that it has a management plan that outlines no more than a biennial inspection and clearing/pruning cycle which is designed to achieve under normal growth conditions the minimum clearance space requirements specified in Tables 9.3, 10.1, 10.2 and 10.3 of the 2005 Line Clearance Code. • For low voltage lines in LBRA, CitiPower/Powercor Australia is exempted from the requirement to maintain the clearance space in accordance with clause 2.1 of the 2005 Line Clearance Code provided it has a management plan that outlines an inspection and/or clearing/pruning cycle of no more than three years which is designed to achieve under normal growth conditions, the minimum clearance space requirements specified in Tables 9.3, 10.1 and 10.2 of the 2005 Line Clearance Code.
23/01/06	Appeals to ESCV Appeal Panel from ESCV's 2006-10 EDPR resumed	When the appeals resumed CitiPower/Powercor Australia indicated that the exemptions granted by ESV largely aligned what was required for high voltage wires in LBRA with its practical compliance regime. However, it was not satisfied that the exemption granted aligned with its practical compliance regime for low voltage wires in LBRA. Accordingly, the appeals proceeded with CitiPower/Powercor Australia seeking a lower quantum of cost allowance.
17/02/06	ESCV Appeal Panel Decision[41]	ESCV Appeal Panel: • Determined that CitiPower/Powercor Australia's desire to move from practical compliance to literal compliance with the 2005 Line Clearance Regulations (with exemption) for low voltage wires in LBRA does not constitute a step change. • Dismissed CitiPower/Powercor Australia's claims that an additional revenue allowance for the costs of literal compliance with the 2005 Line Clearance Regulations (with exemption) should be provided by making an appropriate opex adjustment as an alternative to its treatment as a step change. This was inappropriate as CitiPower/Powercor Australia had consistently presented this as a step change. Further, CitiPower/Powercor Australia could readily have expended available revenue in the past regulatory period on an expanded vegetation clearance program had it opted to do so. That expenditure would have formed part of its base opex. • Noted that at the time the ESCV made its decision CitiPower/Powercor Australia's ESMS had been approved by ESV and ESV had stated that it did not intend to alter its enforcement activities regarding vegetation clearance. There was ample evidence before the ESCV of an intention on the part of ESV to treat CitiPower/Powercor Australia's present compliance regime as

[41] Attachment 243 to this Revised Regulatory Proposal.

Date	Event	Description
		adequate. • Determined that faced with the material before it from CitiPower/Powercor Australia and ESV, CitiPower/Powercor Australia's prior compliance history and the lack of any substantive change in the 2005 Line Clearance Regulations or step change, it was open to the ESCV to form the view it did. It was reasonable for the ESCV to exclude the costs of maintaining literal compliance with the 2005 Line Clearance Regulations at all times and in all places when forecasting CitiPower/Powercor Australia's prescribed services revenue requirement.
12/10/06	ESCV's 2006-10 EDPR (amended in accordance with ESCV Appeal Panel's decision) (published on 19/10/06)[42]	Confirmed that given ESV had indicated that it only intends to enforce literal compliance with the requirements imposed by 2005 Line Clearance Regulations as to the clearance between electric lines and vegetation during Proclaimed Fire Declaration Period, a reasonable allowance for the costs of complying with those Regulations is one that is based on literal compliance with the 2005 Line Clearance Regulations during Proclaimed Fire Declaration Periods.
2006-08	CitiPower and Powercor Australia undertook a detailed inspection of LBRA areas[43]	An enhanced inspection of LBRA was undertaken to quantify the workload required to comply with the 2005 Line Clearance Regulations by 2014. It was proposed that compliance be achieved by a two cut strategy - first cutting for clearances and secondly cutting for regrowth. This strategy was due to aesthetic reasons to maintain customer satisfaction. The inspection program was established in 2006 and was completed in 2008.
3/09/08	Kieran Skelton, Richard Scholten and Garry Audley of Power/CitiPower met with Robert Skene and Ken Gardner of ESV[44]	CitiPower/Powercor Australia presented LBRA compliance strategy to ESV. CitiPower/Powercor Australia understood at the meeting ESV supported a staged process to achieve compliance by 2014. First stage to cut for clearance and the second stage to cut for regrowth.
23/02/09	Letters from Garry Audley General Manager, Electricity Networks, CitiPower and Powercor Australia to Ken Gardner, Director of Energy Safety	Enclosing Powercor Australia's 2009-10 Vegetation Management Plan and CitiPower's 2009-10 Vegetation Management Plan.
2/03/09	Letters from Robert Skene Manager, Risk Management & Audit ESV to Garry Audley General Manager Electricity Networks	ESV acknowledged receipt of Vegetation Management Plans for CitiPower and Powercor Australia.

[42] Attachment 31 to this Revised Regulatory Proposal.
[43] Letter from CitiPower/Powercor Australia to ESV dated 4 August 2009 (Attachment 248 to this Revised Regulatory Proposal), at 1.1.4.
[44] Email from Garry Audley to Ken Gardner dated 13 May 2009 (Attachment 248 to this Revised Regulatory Proposal). CitiPower Pty and Powercor Australia Ltd Ched Services risk Management and Compliance Committee (Attachment 248 to this Revised Regulatory Proposal), at 1.1.4.

Date	Event	Description
	CitiPower/Powercor Australia[45]	
7/05/09	Letters from Ken Gardner Director of Energy Safety, ESV to Garry Audley General Manager Electricity Networks CitiPower/Powercor Australia[46]	ESV confirmed that it was not in a position to approve the Powercor Australia and CitiPower Vegetation Management Plans as they did not comply with the requirements of the Electricity Safety Act and the 2005 Line Clearance Regulations, including the 2005 Line Clearance Code. ESV noted that the staged approach in the plans to achieve compliance with the 2005 Line Clearance Code clearance requirements by the end of 2014 did not meet the approval criteria. ESV requested Powercor Australia and CitiPower to provide a management plan designed to achieve compliance to the 2005 Line Clearance Code clearances, including allowances for regrowth, consistent with the current exemption that came into effect on 21 December 2005.
13/05/09	Email from Garry Audley to Ken Gardner, ESV[47]	Refers to letters from ESV of 7/05/09. Notes that at the meeting of 3/09/08 CitiPower/Powercor Australia understood that ESV supported the strategy aimed at achieving LBRA compliance by 2014 by a staged process. On the basis of this understanding CitiPower/Powercor Australia signed a new 5 year Vegetation Contract to achieve this enhanced program. Notes that CitiPower/Powercor Australia remain fully compliant for HBRA [with the exemptions] and the staged component only relates to LBRA. Requests meeting with Ken Gardner.
19/05/09	Meeting between Garry Audley and Ken Gardner	Meeting between Garry Audley and Ken Gardner to discuss the non-approval of the Vegetation Management Plans.
12/06/09	Letter from Garry Audley General Manager Electricity Networks CitiPower/Powercor Australia to Ken Gardner Director of Energy Safety ESV[48]	Informs ESV that Powercor Australia entered into a 5 year contract with VEMCO for vegetation management works after discussing with ESV its proposed approach for compliance. Powercor Australia was surprised by ESV's recent letters indicating non-approval of its Vegetation Management Plan. Notes that CitiPower/Powercor Australia has made every endeavour to accommodate ESV's completely different approach. Informs ESV that it is possible for CitiPower/Powercor Australia to achieve compliance by the end of 2012 by commencing the 3 year cycle in July 2009 cutting for both clearance and regrowth. States that if ESV supports this approach CitiPower/Powercor Australia will resubmit both Vegetation Management Plans on this basis.
30/07/09	Letter from Ken Gardner, Director of Energy Safety ESV to	Refers to letter of 12/06/09 from CitiPower/Powercor Australia. Requests a detailed explanation as to why CitiPower/Powercor Australia are not

45 Attachment 248 to this Revised Regulatory Proposal.
46 Attachment 248 to this Revised Regulatory Proposal.
47 Attachment 248 to this Revised Regulatory Proposal.
48 Attachment 248 to this Revised Regulatory Proposal.

Date	Event	Description
	John Misfund Acting General Manager Electricity Networks CitiPower/Powercor Australia[49]	able to achieve and maintain the required 2005 Line Clearance Code clearance in a time frame less than the end of 2012. Notes that ESV requires this information to decide whether that approach could be supported.
4/08/09	Letter from Garry Audley, General Manager Electricity Networks Citipower/Powercor Australia to Ken Gardner Director of Energy Safety ESV[50]	Provides additional explanation as to why CitiPower/Powercor Australia are not able to achieve and maintain the required 2005 Line Clearance Code clearance until the end of 2012. Notes that from 2006-2008 a detailed assessment of LBRA areas was undertaken to quantify the workload required to comply with the 2005 Line Clearance Regulations. This assessment was agreed between ESV and Powercor Australia as necessary to quantify the extent of non-compliance. The assessment identified 20,000 LBRA non-compliant spans that Powercor Australia is responsible for clearing. Clearing the spans would require a minimum of 1 visit per site. Based on a 2 year High Voltage cycle and a 3 year Low Voltage cycle Powercor Australia estimated that the earliest compliance achievement would be 3 years from the date of commencement being the end of 2012. The assessment also identified 3,000 spans that Powercor Australia and other responsible persons must clear and 17000 spans which must be cleared by other responsible persons. Powercor Australia requested confirmation from ESV that all other responsible persons within its geographic area would also be directed to comply within the same timeframe.
5/10/09	Meeting between Garry Audley and Chris Mulherron (Powercor Australia) and Paul Fearon and Robert Skene (ESV)	ESV informed Powercor Australia that they would give conditional approval to the Vegetation Management Plan on the basis that compliance with the 2005 Line Clearance Regulations is achieved by 2012.
13/10/09	General Managers forum[51] ESV confirmed that it would not re-create the exemptions following the remaking of the 2005 Line Clearance Regulations.	Paul Fearon Director ESV confirmed the intention of ESV to remake the 2005 Line Clearance Regulations prior to the sunsetting of those Regulations. Also confirmed the exemptions would cease to have any effect when those Regulations sunset. Confirmed that ESV did not intend to re-create the exemptions following the remaking of the 2005 Line Clearance Regulations.
10/09	CitiPower/Powercor Australia provided its revised 2009/10 management plan to	CitiPower/Powercor Australia provided its revised 2009/10 Vegetation Management Plans to ESV. The plan noted that it was designed to provide a staged and measured approach for CitiPower/Powercor Australia to achieve compliance with the 2005 Line Clearance Regulations [with the exemption] by the end of 2012.

[49] Attachment 248 to this Revised Regulatory Proposal.
[50] Attachment 248 to this Revised Regulatory Proposal.
[51] Letter from Paul Fearon, Director ESV to Garry Audley General Manager Electricity Networks Powercor Australia dated 7 December 2009 (Attachment 248 to this Revised Regulatory Proposal).

Date	Event	Description
	ESV	
28/10/09	Letter from Paul Fearon, Acting Director of Energy Safety ESV to Garry Audley, General Manager Electricity Networks Powercor Australia[52]	Responds to Powercor Australia's letter of 4/08/09. ESV is supportive of the efforts Powercor Australia has taken to address the long standing 2005 Line Clearance Code non-compliance issues in its LBRA. ESV would consider conditionally approving Powercor Australia and CitiPower Vegetation Management Plans were they to contain the commitment that all future pruning and clearing works were designed to both achieve and maintain the minimum clearance space contained in the 2005 Line Clearance Code in accordance with the December 2005 exemption. Conditions that might be applied to the approval of these plans would be the establishment of a 6 monthly reporting to ESV of the progress made in the reduction of the2005 Line Clearance Code noncompliance in the LBRA where Powercor Australia is the responsible person.
7/12/09	Letter from Director General Energy Safety to Powercor Australia[53]	ESV confirmed that it did not intend to re-create the exemptions created in December 2005 and early 2006 after the sunsetting of the 2005 Line Clearance Regulations.
25/02/09	ESV published Line Clearance RIS[54]	Proposed 2010 Line Clearance Regulations do not contain in any form the exemptions granted in respect of the 2005 Line Clearance Regulations. Public comments due on the proposed Regulations by 25/05/09.
20/05/10	Letter from Garry Audley, General Manager Electricity Networks CitiPower/Powercor Australia to Paul Fearon, Acting Director General of Energy Safety ESV [55]	Letter containing submission in response to the Line Clearance RIS. CitiPower/Powercor Australia recommended changes to the Proposed 2010 Line Clearance Regulations. CitiPower/Powercor Australia informed the ESV that the changes between the 2005 Line Clearance Regulations and the proposed 2010 Line Clearance Regulations would result in increased costs of compliance.
29/06/10	2010 Line Clearance Regulations	2010 Line Clearance Regulations commence. None of the changes recommended by CitiPower/Powercor Australia are included in the those Regulations. There is a change to the notification requirement between the draft which was the subject of public consultation and the final version 2010 Line Clearance Regulations being that notice of cutting/clearing of trees must also be given to affected person where the cutting/clearing is on public land.

[52] Attachment 248 to this Revised Regulatory Proposal.
[53] Attachment 248 to this Revised Regulatory Proposal.
[54] Attachment 241 to this Revised Regulatory Proposal.
[55] Attachment 242 to this Revised Regulatory Proposal.

Appendix 9.1 - Metro 2012 and CBD Security of Supply projects

Introduction

CitiPower submits that additional expenditure forecast in respect of its Metro 2012 and CBD Security of Supply projects forecasts is prudent and efficient.

As was foreshowed by SKM at the time the CBD Security of Supply and Metro 2012 regulatory test estimates were provided to the ESCV, the two areas where SKM's estimates were prone to inaccuracy were cable routes and building refurbishment costs.[1]

The cable installation costs proposed by CitiPower are efficient. A tender process for the complete detail design, manufacture and installation of the cables has been conducted and the lowest cost tender selected. That tender process evidences the fact that the forecast costs have not been overestimated.

The building refurbishment and construction costs have been arrived at by consideration of the civil construction options, as well as external service provider estimates and quotes for the works at BQ (Bouverie-Queen), VM (Victoria Market) and W (Waratah Place).

Further, since the design, procurement, construction and project management activities for the Metro 2012 and the CBD Security of Supply projects were carried out jointly, CitiPower considers that the costs for both of these projects can be considered efficient.

While the costs submitted by CitiPower at the time of the regulatory tests, are slightly below the actual costs, the regulatory tests are likely to have significantly understated the benefits of both projects. The benefits of the projects were understated as a result of AEMO increasing the commercial VCR in 2009 by a factor of 66 per cent, from the value of $62,215 used in the regulatory test, to the current value of $103,240.[2]

Further, the reason why the costs submitted by CitiPower at the time of the regulatory tests are different to the forecast cost in CitiPower's Initial Regulatory Proposal and this Revised Regulatory Proposal can be explained in part by the two areas of potential inaccuracy in estimating the costs referred to in SKM's report provided to the ESCV, being cable routes and building refurbishment costs.[3] This is explained in further detail below.

The following table compares the costs proposed for the Metro 2012 and CBD Security of Supply projects with the regulatory test values.

[1] SKM, Review of CBD Security of Supply and Planning Standards, 22 August 2006 (annexed to CitiPower's Melbourne CBD Security of Supply Enhancement Project, Submission to the Essential Services Commission, 11 September 2006 (Attachment 255 to this Revised Regulatory Proposal), p40.

[2] Refer to Victorian DNSPs, 2009 TCPR (Attachment 251 to this Revised Regulatory Proposal).

[3] SKM, Review of CBD Security of Supply and Planning Standards, 22 August 2006 (annexed to CitiPower's Melbourne CBD Security of Supply Enhancement Project, Submission to the Essential Services Commission, 11 September 2006 (Attachment 255 to this Revised Regulatory Proposal), p40.

CBD security of supply and Metro 2012 project Costs	$2010M			Total cost comparison with amounts in ESCV processes
	Escalated costs from ESCV processes	Direct costs in the Initial and Revised Regulatory Proposals	Less actual spend in current period	
CBD Security	$56.0	$63.5	$54.5	113%
Metro 2012 – Stage 1		$33.3	$17.9	
Metro 2012 – Stage 2		$19.6	$19.6	
Metro 2012 Total	$43.4	$52.9	$37.5	122%

Table A9.1.1 - Costs proposed for Metro 2012 and CBD security of supply projects, in comparison with the regulatory test values

Reasons for differences between forecast costs and regulatory test costs

As noted above, the reason why the costs submitted by CitiPower at the time of the regulatory tests are different to the forecast cost in CitiPower's Initial Regulatory Proposal can be explained in part by the two areas of potential inaccuracy in estimating the costs referred to in SKM's report provided to the ESCV.

The regulatory tests were based on estimates provided by SKM on the basis of the best available information at that time. SKM stated that:[4]

> *'The costs are estimates only and may vary when subject to detailed analysis. In particular there are two areas where the estimate of costs will be prone to inaccuracy. The two areas are:*
>
> - *Cable routes into the CBD. The cable routes are likely to be subject to space constraints and congestion. The assumed route lengths could be quite different once these issues are taken into account and the routes are fully determined and surveyed.*
> - *Building refurbishment costs. Refurbishment costs are difficult to estimate accurately without a detailed building survey being undertaken and is beyond the scope of this report. However, SKM has provided a brief report on refurbishment costs in Appendix K that aims to capture some of the major costs of refurbishment. These costs have been incorporated into the cost analysis.'*

The estimates by SKM, as used in each of the regulatory tests, are direct project costs. Business overheads were not included in the distribution works undertaken by CitiPower or the transmission works undertaken SP AusNet.

The reasons why these two areas of uncertainty identified by SKM have contributed to the forecast costs exceeding the cost estimates used in the regulatory tests are set out in more detail below. The discussion below also shows that the forecast costs for the Metro 2012 and CBD Security of Supply projects in CitiPower's Initial Regulatory Proposal and this Revised Regulatory Proposal are in some cases lower than current forecast costs.

[4] SKM, Review of CBD Security of Supply and Planning Standards, 22 August 2006 (annexed to CitiPower's Melbourne CBD Security of Supply Enhancement Project, Submission to the Essential Services Commission, 11 September 2006 (Attachment 255 to this Revised Regulatory Proposal), p40.

66kV cable installation costs

Table A9.1.2 below compares the cable costs estimated through the prior ESCV process and the forecasts contained in the Initial Regulatory Proposal, factoring in the final route requirements, as well as the current requirements for traffic management in the Melbourne CBD area.

Cable Cost Comparison	Regulatory Test		Forecast		Diff ($M)
	Cct kms	Cost ($M)	Cct kms	Cost ($M)	
Install 2 x 66kV 120MVA Cables from BTS-BQ	5.33	$24.04	5.33	$21.93	-$2.12
Install 1 x 66kV 120MVA Cables from BTS-VM	7.5	$15.60	6.43	$24.93	$9.33
Install 2 x 66kV 120MVA Cables from BQ-VM	1.95	$8.45	1.1	$6.83	-$1.62
Install 2 x 66kV 120MVA Cables from BQ-W	2	$8.66	1.3	$8.08	-$0.58
Redirect VM-WA Feeder		$0.23	0.1	$0.50	$0.27
Total Cable Cost Difference					**$5.28**
Average cost: Circuit km	**$3.81 M/km**		**$5.10 M/km**		

Table A9.1.2 Comparison of cable installation costs ($2010 excluding overheads and escalation)

The forecast costs in the Initial Regulatory Proposal were based on the most recent information at the time of submission. Those forecasts were derived from detailed feasibility studies, preliminary quotes and designs. The final cable routes varied from the initial estimates as a result of the detail design and feasibility studies, and in determining the optimum cable routes, some cable lengths were actually shorter than originally estimated by SKM.

Prior to the submission of the Revised Regulatory Proposal, CitiPower conducted a market tender process. The cable requirements for the Metro 2012 and CBD security of supply projects were tendered together to ensure the realisation of the maximum possible cost efficiencies, and to minimise, streamline and co-ordinate the communication process with all external stakeholders including Councils, authorities, landowners, public and communities. Sixteen respondents replied to an expression of interest sought from the open market within Australia and four were selected to provide a tender.[5] The evaluation of the tenders is detailed in the confidential Memo to the Board regarding supplier recommendations for network services activities.[6]

The tender process indicated that the forecasts included in the Initial Regulatory Proposal marginally underestimated the costs for the cable installation. The most recent update on the costs for stage 1 of the underground works (BTS-VM-BQ-BTS) is detailed in Table A9.1.3, with over 90 per cent of the total costs based on a tender submission for the construction and installation of the cables.

[5] CitiPower, Memorandum regarding provision of Cable Design Services and Installation of Three Underground 66kV High Voltage Three Phase Circuits – Metro 2012 & CBD Security Project for CitiPower Supplier Recommendation, annexed to the CitiPower / PNS, Memo to the Board of Directors regarding supplier recommendation for network services activities, 25 May 2010 (Attachment 259 to this Revised Regulatory Proposal), p1.

[6] Attachment 259 to this Revised Regulatory Proposal.

Cable Cost Comparison	Forecast	Latest Quotes	Diff ($M)
	Cost ($M)	Cost ($M) (July 2010)	
Stage 1 (BTS-VM-BQ-BTS)	$28.64	$29.78	$1.14
Install 1 x 66kV 120MVA Cables from BTS-BQ	$19.65	$19.91	$0.26
Install 1 x 66kV 120MVA Cables from BQ-VM	$5.39	$4.09	-$1.30
Install 2 x 66kV 120MVA Cables from BQ-W	$8.08	$8.52	$0.44
Redirect VM-WA Feeder	$0.50	$0.48	-$0.02
Total Cost	**$62.26M**	**$62.77M**	

Table A9.1.3 Comparison of cable installation costs ($2010 excluding overheads and escalation)

The costs for the remaining cable works are based on the firm quotes for Stage 1.

Nonetheless, CitiPower has maintained the forecasts included in the Initial Regulatory Proposal in this Revised Regulatory Proposal. Compared to the values submitted in the regulatory test, the additional $5.28 million ($2010) included in the Initial and the Revised Regulatory Proposals, represents an increase of 9.26 per cent in cable installation costs. The market-based quotes show that this increase is conservative, and the AER should be satisfied that the additional expenditure proposed in respect of cable installation is efficient and prudent.

Building refurbishment costs

Table A.9.1.4 below shows the refurbishment and installation costs at each zone substation, comparing the regulatory test value with the Initial and Revised Regulatory Proposal forecast and the most recent information obtained on cost estimates, which includes significant externally quoted works. The reasons for these cost variations are explained below.

Station Cost Comparison	Regulatory test	Forecast	Latest Quotes July 2010
	Cost ($M)	Cost ($M)	Cost ($M)
VM Zone Sub: 19 x 66kV GIS CBs	$16.29	$20.16	$20.16
W 66kV Switching: 7 x 66kV GIS CBs	$6.72	$10.03	$12.46[7]
BQ Zone Sub: 11 x 66kV GIS CBs and 2 x 55MVA Txs	$19.38	$23.30	$23.37
Total Stations Cost	**$42.39**	**$53.50**	**$55.98**

Table A9.1.4 Comparison of station costs ($2010 excluding overheads and escalation)

CBD Security of Supply Project

Due to difficulties with the civil arrangements around installing the new 66kV GIS switchgear at the VM zone substation in the existing 66kV switching bay, CitiPower engaged Maunsell (the consultants who had advised the ESCV for the ESCV's Security of Supply Decision), to prepare a report to investigate the options for installation of new 66kV GIS equipment at the VM zone substation.

Maunsell's report[8] was submitted to CitiPower in early 2009 and identified four options for the installation of the GIS switchgear. The least cost option was to use part of the adjacent building as a new 66kV switch room,[9] and this cost of $20.1 million was included in the Initial Regulatory Proposal. The 66kV GIS costs at VM

[7] The quote for W is based on a build up from the firm quotes for BQ and VM.
[8] Maunsell, VM Substation Options Report, 31 March 2009 (Attachment 256 to this Revised Regulatory Proposal).
[9] Maunsell, VM Substation Options Report, 31 March 2009 (Attachment 256 to this Revised Regulatory Proposal), p22.

in Maunsell's report were higher than the regulatory test value by $3.88 million ($2010).

Based on a structural report of W, the long-term plans to convert W into a zone substation outside of this regulatory period and firm quotes for the station work at BQ and VM, costs have increased. The ESCV's Security of Supply Decision highlighted that the ultimate W arrangement would have up to 18 x 66kV GIS circuit breakers.[10]

In its review, Nuttall Consulting recommended the development of W into a zone substation as a likely efficient alternative to some of CitiPower's capital projects.[11] CitiPower is proposing to develop W into a zone substation, but not in this regulatory period. Nevertheless, CitiPower considers that any works undertaken at W for the CBD security of supply project need to consider and not compromise achievement in the future of the ultimate station layout. In the 2011-15 regulatory period, CitiPower has forecast the project to extend the FR-MP 66kV cables into an expanded W switching station as the preferred option to relieve load at risk on the 3 x 66kV RTS cables supplying FR and MP zone substations. This project will ultimately allow MP to be supplied from Brunswick terminal station.

The W building refurbishment costs have increased over those provided for the regulatory test. The $6.63 million ($2010) in the CBD security of supply regulatory test included just over $700,000 for building refurbishment costs. The latest estimates for these works (based on PNS' W civil design brief[12]) has come in at $2.89 million, with the main reasons for the increase being:

- replacement of waterproofing and drainage systems on the roof;
- investigation of all water ingress into the building;
- repairs of all floor and wall cracking;
- removal of internal wall; and
- installation of floor penetration for GIS cable entry.

Metro 2012 Project

The refurbishment costs for the BQ zone substation were estimated by SKM as $19.4 million ($2010).[13] The actual refurbishment costs, including an allowance to raise the roof to accommodate the required equipment, are $23.3 million ($2010). A market tender process has just been completed for BQ and VM. All of the primary plant and civil construction costs have been fixed, and make up over 56 per cent and 42 per cent of the BQ and VM firm quotes respectively.

Staging of the projects

The Metro 2012 scope of works submitted for the regulatory test included installing 2 x 66MVA cables from BTS-BQ and rebuilding BQ zone substation with 2 x 55MVA

[10] ESCV's Security of Supply Decision (Attachment C0192 to the Initial Regulatory Proposal), p18.
[11] Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p98.
[12] Attachment 258 to this Revised Regulatory Proposal.
[13] SKM, Review of CBD Security of Supply and Planning Standards, 22 August 2006 (annexed to CitiPower's Melbourne CBD Security of Supply Enhancement Project, Submission to the Essential Services Commission, 11 September 2006 (Attachment 255 to this Revised Regulatory Proposal), Appendix K.

transformers. CitiPower formed the view that it would be efficient to stage the Metro 2012 project with the CBD Security of Supply project.

The Metro 2012 project's staging was altered so that it would be done in two stages: stage one in conjunction with some of the CBD security of supply works and stage two independently. The scope for the initial stage became:

- rebuild BQ with 2 x 55MVA transformers (Metro 2012);
- install 1 x BTS-BQ cable (Metro 2012), in a common trench with the 1 x BTS-VM cable (CBD Security); and
- install 1 x BQ-VM cable (CBD Security) in a dedicated cable trench.

The second stage involves the installation of the second BTS-BQ cable in a cable trench. It is significant to note that the civil trenching costs are a major component of the cable installation costs, and the regulatory test assumed that the two BTS-BQ cables in the Metro 2012 project would run in one trench. However, it is not feasible to install 3 x 66kV cables in a common trench, so for the three cables from the Brunswick terminal station to the CBD area, one cable requires a separate trench.

It is not practical or economic to construct a trench accommodating three sets of 66kV cables of this size. The required spacing between three sets of cables to allow sufficient heat dissipation to achieve the rating would increase the size of the trench to the point where it is not practical to construct a trench of that size in an inner urban environment.

This staging has not altered the total costs of the 66kV cabling, however, the trenching arrangements were altered to suit the staging, and accordingly the allocation of the civil trenching costs has been re-apportioned between the two projects. Tables A9.1.5 and A9.1.6 below explain how the costs have been divided across the two projects.

Trenching and works staging comparison	Regulatory Test	
	Metro	CBD
Install 2 x 66kV 120MVA Cables from BTS-BQ	$24.04	
Install 1 x 66kV 120MVA Cables from BTS-VM		$15.60

Table A9.1.5 Regulatory test, trenching and cable costs

Trenching and works staging comparison	Forecasts			Latest Quote
	Metro	CBD	Total	
Install 3 x 66kV 120MVA Cables: 1 x BTS-BQ, and then 1 x BQ-VM , in shared trench with 1 x BTS-VM	$9.26	$19.39	$28.64	$29.78
Install 1 x 66kV 120MVA Cables from BTS-BQ in single trench	$19.65		$19.65	$19.91
Total costs	$28.91	$19.39	**$48.30**	**$49.69**

Table A9.1.6 Revised Regulatory Proposal forecasts, trenching and cable costs

CitiPower notes that Table A9.1.6 does not include the cable estimates for the following works (included in Table A9.1.3):

- install 1 x 66kV 120MVA cable from BQ-VM;
- install 2 x 66kV 120MVA Cables from BQ-W; and

- redirect VM-WA feeder.

Rather than install two cables from BTS-BQ from the outset, the combined stage one works now creates a BTS-VM-BQ loop. CitiPower determined that staging the project this way was a prudent means of managing the supply security risks from any late completion by SP AusNet of the Brunswick terminal station works. In the event of a delay in the Brunswick terminal station works, the cable running between BQ and VM will enable BQ to be energised from WMTS initially and load transferred from VM to BQ ensuring VM transformation capacity does not exceed its N rating.

Conclusion

Considering the nature of the Metro 2012 and CBD Security of Supply projects, the cost forecasts included in the Revised Regulatory Proposal are within a reasonable range of the values used in the regulatory test, having regard to the areas of uncertainty highlighted in the SKM report. The forecasts in this Revised Regulatory Proposal are considered to be conservative, with some risk of being greater than actual expenditure given the recent update of the forecasts in July 2010.

The cable installation costs are considered efficient due to the tender process for the complete detail design, manufacture and installation of the cables which proves that the forecast costs have not been over-estimated.

The zone substation refurbishment and construction costs have been arrived at by consideration of the civil construction options, as well as external service provider estimates and quotes for the works at BQ, VM and W.

Further, since the design, procurement, construction and project management activities for the Metro 2012 and the CBD Security of Supply projects was carried out jointly, CitiPower considers that the costs for both of these projects can be considered efficient.

While the costs at the time of the regulatory test are slightly below the actual costs, the regulatory test is likely to have significantly understated the benefits of both projects. The benefits were understated as a result of AEMO increasing the commercial VCR in 2009 by a factor of 66 per cent from the value of $62,215 used in the regulatory test, to the current value of $103,240.[14] Further, the reason why the costs submitted by CitiPower at the time of the regulatory tests are different to the forecast cost in CitiPower's Initial Regulatory Proposal and this Revised Regulatory Proposal can be explained in part by the two areas of potential inaccuracy in estimating the costs referred to in SKM's report provided to the ESCV (cable routes and building refurbishment costs).[15]

[14] Refer to Victorian DNSPs, 2009 TCPR (Attachment 251 to this Revised Regulatory Proposal).

[15] SKM, Review of CBD Security of Supply and Planning Standards, 22 August 2006 (annexed to CitiPower's Melbourne CBD Security of Supply Enhancement Project, Submission to the Essential Services Commission, 11 September 2006 (Attachment 255 to this Revised Regulatory Proposal), p40.

Appendix 16.1 - Close out of the S Factor Scheme

In this Appendix, CitiPower sets out its proposed method for calculating the S factor true up amount and the reasons why it does not accept the AER's proposed method set out in the Draft Determination.

ESCV S Factor Scheme

The ESCV's S Factor scheme under the ESCV's 2006-10 EDPR was designed to be continuous and operate across regulatory periods. Under the ESCV scheme, any incremental change in service performance in one year compared to the previous year is financially rewarded / penalised for six years through a change to capped prices (with a two-year lag).

If there is a good / poor service performance year, preceded and followed by average service performance years, there will result a revenue increment / decrement in the first year and the opposite revenue increment / decrement in the seventh year. This is illustrated in the following example which assumes:

- average performance in every year except 2010, which experiences worse than average performance; and
- a unit of good / poor performance translates into a unit of revenue increment / decrement.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual performance	100	100	110	100	100	100	100	100			
ESCV Scheme incremental performance		0	10	-10	0	0	0	0			
Reward due to 2010 incremental performance					-10	-10	-10	-10	-10	-10	
Reward due to 2011 incremental performance						10	10	10	10	10	10
Total reward				**0**	**-10**	**0**	**0**	**0**	**0**	**0**	**10**

Table A16.1.1 Example of operation of ESCV scheme

Thus, if the ESCV scheme had continued, it would have provided revenue increments and/or decrements in respect of performance in 2010 for:

- 2010 performance relative to 2009 performance; and
- 2011 performance relative to 2010 performance.

AER's Draft Determination

The AER issued a model with its Draft Determination titled 'CitiPower - S-factor true up - draft decision.xls' to calculate the ESCV scheme true up amount, and has proposed its new STPIS which will operate from 2011. Under the STPIS, performance in any year is compared to a target for that year (with a two-year lag), and any difference is rewarded or penalised by a change to capped prices in a single year.

Below is an illustration of how the AER's S Factor true up model and its STPIS scheme would operate together on the equivalent actual performance assumed above.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AER STPIS target				100	100	100	100	100			
Actual performance	100	100	110	100	100	100	100	100			
ESCV Scheme incremental performance		0	10								
Reward due to 2010 incremental performance					-10	-10	-10	-10	-10	-10	
Reward from AER STPIS Scheme						0	0	0	0	0	
Total reward				**0**	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	**0**

Table A16.1.2 Example of operation of STPIS and AER's S Factor true up model

The AER's S Factor true up model in combination with its STPIS provides revenue increments and/or decrements for:

- 2010 performance relative to 2009 performance; and
- 2011 performance relative to 2011 STPIS target.

The revenue increments/decrements under the AER's approach should be the same as if the ESCV scheme had continued (see Table A16.1 above) because the performance from 2011-15 is assumed to remain at average levels. However, that is not the case under the AER's approach. In order for the AER's approach to result in the same revenue increments and/or decrements that would have arisen from the ESCV scheme, the following term should also be included in the AER's S Factor true up model:

- 2011 STPIS target relative to 2010 performance.

This illustrates that the AER's approach in the Draft Determination does not replicate the revenue increments and/or decrements which would arise under the ESCV scheme had it continued.

CitiPower's Initial Regulatory Proposal and Revised Regulatory Proposal

CitiPower's Revised Regulatory Proposal proposes the same solution to the close out of the ESCV S Factor Scheme as in its Initial Regulatory Proposal. There is no evidence in the Draft Determination that the AER considered CitiPower's Initial Regulatory Proposal on this matter.

CitiPower proposes that to properly close out the ESCV scheme, the calculation must include the calculation of the revenue increments or decrements arising from the incremental change in service performance between the STPIS targets for 2011 and performance in 2010. 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 S Factor true up calculation are proposed to be based on actual average service performance over 2005-09, applying the current regulatory control period exclusion criteria.

Below is an illustration of how CitiPower's proposed ESCV scheme true up calculation and the AER's STPIS would operate together on the equivalent assumed performance in the prior examples.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AER target				100	100	100	100	100			
Actual performance	100	100	110	100	100	100	100	100			
ESCV Scheme incremental performance		0	10	-10							
Reward due to 2010 incremental performance					-10	-10	-10	-10	-10	-10	
Reward due to 2011 incremental performance						10	10	10	10	10	10
Reward from AER STPIS Scheme				0	0	0	0	0	0	0	0
Total reward				**0**	**-10**	**0**	**0**	**0**	**0**	**0**	**10**

Table A16.1.3 Example of operation of CitiPower's proposed approach

CitiPower's proposed calculation in combination with the AER's STPIS provides revenue increments and/or decrements arising from service performance in 2010 for:

- 2010 performance relative to 2009 performance;
- 2011 performance relative to 2011 STPIS target; and
- 2011 STPIS target relative to 2010 performance.

This mirrors the revenue increments and/or decrements which would have arisen had the ESCV scheme continued.

Appendix 19.1 - CitiPower's Proposed Charges for Alternative Control Services

In this Appendix CitiPower sets out its proposed charges for fee based alternative control services, labour rates for quoted alternative control services and prices for public lighting.

Charges for fee based alternative control services

In this Revised Regulatory Proposal, CitiPower proposes the following charges for fee based alternative control services.

CitiPower Alternative Control services - Fee Based Services	2011 Charges ($2010)
Meter Accuracy Test - single phase (BH)	361.17
Meter Accuracy Test - single phase (AH)	393.62
Meter Accuracy Test - Single phase additional meter (BH)	143.99
Meter Accuracy Test - multi phase (BH)	460.56
Meter Accuracy Test - multi phase (AH)	502.91
Meter Accuracy Test - Multi phase additional meter (BH)	247.88
Meter Accuracy Test - CT (BH)	450.83
Meter Accuracy Test - CT (AH)	492.21
Meter Investigation Test (BH)	287.74
Meter Investigation Test (AH)	312.88
Reconnections (incl Customer Transfer) BH	13.27
Reconnections (same day) BH	16.63
Reconnections (incl Customer Transfer) AH	56.62
Disconnection (BH only)	13.45
Disconnection (no AH service)	-
Disconnection for non payment (BH only)	13.45
Special reading BH	10.29
Special reading AH - no service	-
Service Truck Visit BH	462.37
Service Truck Visit AH	504.40
Wasted Truck Visit BH	320.44
Wasted Truck Visit AH	350.34
Reserve Feeder - Subtransmission - $ per KVA	1.43
Reserve Feeder - High Voltage - $ per KVA	2.95
Reserve Feeder - Low Voltage - $ per KVA	7.29

CitiPower Alternative Control services - Fee Based Services	2011 Charges ($2010)
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh BH	355.23
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh AH	389.34
New Connections Responsible for metering	
Single phase BH	459.20
Single phase AH	489.58
Multi phase DC BH	548.00
Multi phase DC AH	578.38
Multi phase CT BH	2,052.57
Multi phase CT AH	2,215.43
New Connections Not Responsible for metering	
Single phase BH	401.54
Single phase AH	431.93
Multi phase DC BH	490.35
Multi phase DC AH	520.73
Multi phase CT BH	1,994.92
Multi phase CT AH	2,157.78
Solar PV Conn - Single phase BH (unit cost)	215.99
Solar PV Conn - Single phase AH (unit cost)	230.13

Table A19.1.1 CitiPower's proposed charges for fee based alternative control services

Labour rates for quoted alternative control services

In this Revised Regulatory Proposal, CitiPower proposes the following labour rates for quoted alternative control services.

CitiPower Alternate Control Service - Proposed Quoted Services	2011 $'s Per hour per Person (Real $2010 ex GST)
General Line Worker - Business Hours	115.14
General Line Worker - After Hours	126.61
Design/Survey - Business Hours	123.56
Design/Survey - After Hours	139.16
Administration	47.85

Table A19.1.2 CitiPower's proposed labour rates for quoted alternative control services

Prices for public lighting

In this Revised Regulatory Proposal, CitiPower proposes the following prices for public lighting.

Public Lighting Prices	2011 Charges Real $2010 (ex GST)
Mercury vapour 80 watt	65.82
Sodium high pressure 150 watt	100.71
Sodium high pressure 250 watt	102.36
Fluorescent 20 watt	130.98
Fluorescent 40 watt	131.64
Mercury vapour 50 watt	93.46
Mercury vapour 125 watt	103.99
Mercury vapour 250 watt	85.98
Mercury vapour 400 watt	87.01
Mercury vapour 700 watt	127.95
Sodium high pressure 70 watt	139.54
Sodium high pressure 100 watt	102.73
Sodium high pressure 220 watt	102.56
Sodium high pressure 360 watt	104.41
Sodium high pressure 400 watt	112.60
Sodium high pressure 1000 watt	202.67
Metal halide 70 watt	215.23
Metal halide 100 watt	158.12
Metal halide 150 watt	159.13
Metal halide 250 watt	122.83
Metal halide 400 watt	122.83
Metal halide 1000 watt	183.22
T5 2X14W	38.19

Table A19.1.3 CitiPower's proposed prices for public lighting