



**POWERCOR AUSTRALIA LIMITED**

**REVISED REGULATORY PROPOSAL:  
2011 TO 2015**

**21 JULY 2010**

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**Powercor Australia'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	<i>Code of Practice for Electric Line Clearance 2005</i>
2005 Line Clearance Regulations	<i>Electricity Safety (Electric Line Clearance) Regulations 2005</i>
2009 TCPR	Victorian DNSPs, Transmission Connection Planning Report Produced jointly by the Victorian Electricity Distribution Businesses, 2009
2010 Line Clearance Code	<i>Code of Practice for Electric Line Clearance 2010</i>
2010 Line Clearance Regulations	<i>Electricity Safety (Electric Line Safety) Regulations 2010</i>
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
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

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<b>Term</b>	<b>Description</b>
	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 Commission	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
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

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<b>Term</b>	<b>Description</b>
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 Agreement	The agreement of titled 'Powercor 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 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

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Term	Description
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 Guideline	Efficiency Benefit Sharing Scheme published by the AER on 26 June 2008 in accordance with 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	<i>Electricity Industry Act 2000 (Vic)</i>
Electricity Safety Act	<i>Electricity Safety Act 1998 (Vic)</i>
Electricity Safety Management Regulations	<i>Electricity Safety (Management) Regulations 2009 (Vic)</i>
Electricity System	ORG, Electricity System Code, October 2000

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Term	Description
Code	
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	<i>Essential Services Commission Act 2001 (Vic)</i>
ESCV	Essential Services Commission of Victoria
ESCV Appeal Panel	Appeal Panel established under section 56 of the ESC Act
ESCV Appeal Panel Decision	Reasons for Decision of Appeal Panel in appeal by Powercor Australia dated 17 February 2006, Panel reference: E5/2005
ESCV Credit Decision	ESCV, Credit Support Arrangements, Final Decision, October 2006
ESCV's 2006-10 EDPR	Collectively refers to ESCV, <i>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</i> , 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

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<b>Term</b>	<b>Description</b>
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 Powercor Australia in respect of the 2011-15 regulatory control period
Final Determinations	The AER's impending final distribution determinations for the Victorian DNSPs in respect of the 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 Powercor Australia 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



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<b>Term</b>	<b>Description</b>
Impaq	Impaq Consulting Pty Ltd (ABN 41 005 127 659)
Initial Regulatory Proposal	Powercor Australia'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
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
LPI	Labour Price Index

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Term	Description
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 'Powercor 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	<i>National Electricity (Victoria) Act 2005 (Vic)</i>
NIEIR	National Institute of Economic and Industry Research (ABN 72 006 234)

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Term	Description
	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 <i>Office of Regulator-General Act 1994</i>
ORG Appeal Panel Decision	ORG Appeal Panel, Statement of Reasons for Decision by Appeal Panel in the matter of the <i>Office of Regulator-General Act 1994</i> 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
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

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Term	Description
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 Methodology	Powercor Australia's cost allocation methodology approved by the AER in accordance with clause 6.15.4 of the Rules
Previous Distribution Determinations	Collectively refers to the AER's ACT Final Determination, NSW Final Determination, Queensland Final Determination and South Australian Final Determination
Proclaimed 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 <i>Country Fire Act 1958</i> (Vic) to be a fire danger period in respect of the said country area or part thereof.
Proposed SoRI	The AER's Proposed Electricity transmission and distribution network service providers 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

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<b>Term</b>	<b>Description</b>
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
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

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Term	Description
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 Framework and Approach Paper	The AER's Framework and Approach Paper ETSA Utilities 2010-15 Final Decision, dated November 2008
SP AusNet	SPI Electricity Pty Ltd (ABN 91 064 651 118)
SP AusNet Draft Transmission Determination	The AER's Draft decision SP AusNet transmission determination 2008-09 to 2013-14 dated 31 August 2007
SP AusNet 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	<i>Trade Practices Act 1974 (Cth)</i>
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)

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<b>Term</b>	<b>Description</b>
ULLS Final Decision	The ACCC's assessment of Telstra's Unconditioned Local Loop Service Bank 2 monthly 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, Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal. This Revised Regulatory Proposal contains:

- Powercor Australia's revised regulatory proposal 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 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, Powercor Australia 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 Powercor Australia'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.

Powercor Australia'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 Powercor Australia 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.<sup>1</sup>

### **1.2 Executive summary**

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

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<sup>1</sup> 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 Powercor Australia'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 Powercor Australia's capex program by 36 per cent will have adverse implications for Victorian electricity consumers and the Victorian public, as the AER's Draft Determination compromises Powercor Australia'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.

Powercor Australia 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 Powercor Australia'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.

The AER has also compromised initiatives by Powercor Australia to address the expectations and concerns of the Victorian community with respect to bushfire mitigation by refusing to:

- allow funding to increase preventative maintenance for townships facing high bushfire risk; and
- provide a pass through for the funding of any future costs required to implement any preventative measures arising from the Bushfires Royal Commission.

Powercor Australia is also disappointed by the lack of consistency in distribution regulatory decision making by the AER. Powercor Australia 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

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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 Powercor Australia 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'*;<sup>2</sup>
- 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'*;<sup>3</sup>
- 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;<sup>4</sup> and
- Powercor Australia participated in a survey of DNSPs' market prices for eight typical distribution utility capital works unit rates and SKM concluded that Powercor Australia's 2009 unit rates for capital works (which were used as the unescalated unit rates in forecasting capex for the 2011-15 regulatory control period in the Initial Regulatory Proposal and this Revised Regulatory Proposal) were below the mean of the surveyed unit rates for each of the eight categories of capital works that were subject to the survey and, in six of the categories surveyed, was 15 per cent or more below that mean surveyed rate.<sup>5</sup>

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, Powercor Australia 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

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<sup>2</sup> AER, Draft Determination Appendices, Appendix I, pp60-1.

<sup>3</sup> AER, Draft Determination Appendices, Appendix I, pp68, 69 and 74.

<sup>4</sup> NERA, Review of Operating Expenditure Efficiency, July 2010 (Attachment 102 to this Revised Regulatory Proposal).

<sup>5</sup> SKM, SKM Market Price Survey #4 - Results of Survey for Powercor, 6 July 2010 (Attachment 103 to this Revised Regulatory Proposal).

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 Powercor Australia 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 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, Powercor Australia:

- 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 Powercor Australia takes issue, in section 1.2.2 below.

### **1.2.1 Response to AER's approach in Draft Determination**

As foreshadowed above, Powercor Australia 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**

Powercor Australia 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.

Powercor Australia 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 Powercor Australia'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 Powercor Australia's reinforcement capex projects going ahead, which is a critical determinant of Nuttall Consulting's forecast of Powercor Australia's reinforcement capex, is based entirely on 'judgment' resulting in a forecast of reinforcement capex that is, in turn, qualitative and subjective.
- In assessing Powercor Australia'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. Powercor Australia 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'*<sup>6</sup>;
  - the AER's Jemena Gas Access Final Decision, wherein it is apparent that the AER did not assess whether the margin incurred

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<sup>6</sup> AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p206.

- 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<sup>7</sup>; 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.
- 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*'<sup>8</sup> 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*'.<sup>9</sup> However, in the Draft Determination, the AER rejected Powercor Australia's proposed insurance step change on the basis that it was not satisfied that Powercor Australia's future insurance premiums would increase in the manner forecast by Aon in a report for Powercor Australia. The AER reached this conclusion despite the fact that:
    - the Aon report for Powercor Australia 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
    - Powercor Australia's insurance program is undertaken jointly with CitiPower 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

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<sup>7</sup> AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), pp56-57 and 267-273.

<sup>8</sup> AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p220.

<sup>9</sup> AER, South Australia Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p221.

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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 'foreseeability' since the Previous Distribution Determinations for the ACT, NSW, Queensland and South Australia such that it now considered that 'foreseeability' 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 inconsistent with its inclusion of this event in its Previous Distribution Determinations.
- In rejecting Powercor Australia'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 Powercor Australia'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

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the Transmission-related Costs presently in issue, namely avoided TuOS payments and inter-DNSP payments, in the AER's 'TuOS unders and overs account'.<sup>10</sup>

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 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 Powercor Australia's Transmission-related Costs despite the fact that Powercor Australia is statutorily required to incur these Costs in the provision of standard control services and they are, thus, uncontrollable in nature and quantum.

Powercor Australia 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)
<b>Victorian DNSPs (AER's Draft Determination - real)</b>		
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
<b>Queensland DNSPs (AER's Queensland Final Determination - real)</b>		
Ergon Energy	29.61	5.10
Energex	18.20	7.90
<b>South Australian DNSP (AER's South Australian Final Determination - real)</b>		
ETSA	10.95	3.9

<sup>10</sup> 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.

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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 Powercor Australia'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, Powercor Australia 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, Powercor Australia 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 Powercor Australia's Initial or Current Regulatory Proposal. The statutory test the AER is required to apply in assessing Powercor Australia'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, Powercor Australia is of little probative value in evidencing that the expenditure sought by Powercor Australia is required by it to achieve the opex or capex objectives (as the case may be).

However, in the Draft Determination, the AER assesses Powercor Australia'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. Notable examples include the following:

- In its consideration of the growth drivers proposed by the Victorian DNSPs for the purposes of scale escalation, the AER:



- observed that the Victorian DNSPs proposed ten different growth drivers (nearly all of which were proposed by one DNSP);<sup>11</sup>
- rejected Powercor Australia'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'*<sup>12</sup> and *'CitiPower and Powercor's proposed growth rates result in scale opex forecasts significantly above the other DNSPs'*<sup>13</sup>;
- 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;<sup>14</sup> 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'*.<sup>15</sup>
- Albeit not a view expressly adopted by the AER in its Draft Determination, its expert, Nuttall Consulting, observed, in assessing Powercor Australia's proposed step change for its 'at risk townships program', that this step change was not proposed by SP AusNet and that *'the lack of a claim for SP AusNet for expenditure in this area suggests that the required response may not be as material as suggested by Powercor'*.<sup>16</sup>

### **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.<sup>17</sup> This framework requires the AER to:

- assess Powercor Australia'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.

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<sup>11</sup> AER, Draft Determination, Appendix J, p89.

<sup>12</sup> AER, Draft Determination, Appendix J, p90.

<sup>13</sup> AER, Draft Determination, Appendix J, p95.

<sup>14</sup> AER, Draft Determination, Appendix J, p95.

<sup>15</sup> AER, Draft Determination, Appendix J, p95 and footnote 47.

<sup>16</sup> Nuttall Consulting, Capital Expenditure - Victorian Electricity Distribution Revenue Review, 26 May 2010, p346.

<sup>17</sup> 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).

The Tribunal described the application of this propose and respond framework to a DNSP's forecast opex, in *Application by Energy Australia and Others*<sup>18</sup>, 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.'*

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

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<sup>18</sup> [2009] ACompT 8 at [190] (Attachment 97 to this Revised Regulatory Proposal).

of Powercor Australia'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 Powercor Australia's Initial Regulatory Proposal (at least in part) because Powercor Australia's methodology results in a different forecast or amount to that preferred by the AER. For example:
  - the AER rejects Powercor Australia'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'*;<sup>19</sup> and
  - the AER assumed that historical reliability and quality maintained capex was efficient and, accordingly, assessed Powercor Australia's forecast 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'*.<sup>20</sup> 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 Powercor Australia does not suffice to establish that Powercor Australia'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 Powercor Australia's proposed capex and forecasting substitute capex.<sup>21</sup>

With the exception of customer connections capex (in respect of which Powercor Australia 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*

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<sup>19</sup> AER, Draft Determination, Appendix J, p90.

<sup>20</sup> AER, Draft Determination, pp338-9.

<sup>21</sup> AER, Draft Determination, p288.

*requirements*.<sup>22</sup> 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.<sup>23</sup>

Powercor Australia 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). Powercor Australia 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, Powercor Australia 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.

#### **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.

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

Powercor Australia 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.<sup>24</sup> 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'*.<sup>25</sup>

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

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<sup>22</sup> AER, Draft Determination, pp399, 409, 419 and 429.

<sup>23</sup> ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), p269.

<sup>24</sup> (2009) 175 FCR 201 at [171]-[175].

<sup>25</sup> (2009) 175 FCR 201 at [174] & [175].

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

- 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.<sup>26</sup> The AER concluded that Victorian DNSPs' capex forecasts tend to systematically over estimate actual capex.<sup>27</sup>

Despite this, in the current regulatory control period, Powercor Australia's actual capex in 2006-09 **exceeded** the benchmark set by the ESCV and is expected to exceed the benchmark for 2010 (see Table 1.2 below). The difference is primarily attributable to non-routine new customer connections, which have increased significantly due to stronger than expected growth in customer numbers and steady growth in reinforcement expenditure. This was discussed further in sections 5.5 and 5.10 of the Initial Regulatory Proposal.

	\$'000s (real 2010)					
Capex	2006	2007	2008	2009	2010	Total
Actual/projected	223,199	253,153	242,619	230,007	263,991	1,212,969
Regulatory allowance	203,891	220,924	225,848	222,641	225,806	1,099,111
<b>Difference</b>	<b>19,307</b>	<b>32,230</b>	<b>16,771</b>	<b>7,365</b>	<b>38,185</b>	<b>113,858</b>

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 Powercor Australia'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

<sup>26</sup> AER, Draft Determination, pp291-292, 315, 356-357, 409, 418 & 428.

<sup>27</sup> AER, Draft Determination, pp291-292.



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.<sup>28</sup>

Powercor Australia observes, however, that:

- there is no evidence that Powercor Australia 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<sup>29</sup>, 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.<sup>30</sup>

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.<sup>31</sup> Powercor Australia 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.<sup>32</sup>

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.

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<sup>28</sup> AER, Draft Determination, pp593-4.

<sup>29</sup> NEL, Part 3, Division 4.

<sup>30</sup> NEL ss28N, 28R, 59 and 74; *Criminal Code Act 1995* (Cth), ss137.1 and 137.2 and *Crimes Act 1914* (Cth), s4B(3).

<sup>31</sup> NEL, s28Q(2).

<sup>32</sup> AER, Draft Determination Appendices, pp136-37.

To address the AER's concerns regarding the currency of Powercor Australia's labour cost escalators, Powercor Australia is proposing to engage KPMG to update its labour cost forecasts (relied on by Powercor Australia 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, Powercor Australia is proposing to engage SKM to update its materials escalators (relied on by Powercor Australia 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, Powercor Australia 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 Powercor Australia's Current Regulatory Proposal at any time in the lead up to making its Final Determination, Powercor Australia requests that the AER inform it and offer Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal that would have allowed Powercor Australia 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 Powercor Australia's circumstances or provide any other valid reasons for declining recovery of those costs.

In particular:

- the AER rejected several of Powercor Australia's proposed pass through events on the basis that those events could fall within the existing 'regulatory change event' or 'service standard event' definitions.<sup>33</sup> 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, Powercor Australia has no certainty as to whether it will be able to recover the costs of these events if they do occur;
- the AER rejected Powercor Australia's proposal that additional terms should be added to the control mechanism formula to allow the recovery of Transmission-related Costs.<sup>34</sup> 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 Powercor Australia's proposal that any events that are proposed by Powercor Australia 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.<sup>35</sup> The AER considered that these events may already be covered by the 'regulatory change event' or 'service standard

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<sup>33</sup> AER, Draft Determination, pp708-710.

<sup>34</sup> AER, Draft Determination, pp 62-66.

<sup>35</sup> AER, Draft Determination, p609.

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 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 Powercor Australia.

### **1.2.2 Response to Draft Determination's rejection of Powercor Australia's Initial Regulatory Proposal**

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

- the AER's classification of services in the Draft Determination;
- the AER's decision in respect of Powercor Australia's outsourcing arrangements to:
  - exclude the margin payable by Powercor Australia 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 Powercor Australia 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;



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- 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 Powercor Australia in respect of self insurance;
  - the step change proposed by Powercor Australia in respect of compliance with the Electricity Safety Management Regulations;
  - the step change proposed by Powercor Australia in respect of the national framework for distribution network planning and expansion;
  - the step change proposed by Powercor Australia 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. Powercor Australia 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 Powercor Australia 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 determination of a major event day threshold of 2.8 beta for the purposes of the STPIS;
- 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 Powercor Australia'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 Powercor Australia to its Initial Regulatory Proposal include the revisions required to incorporate Powercor Australia's acceptance of the matters detailed above in its Current Regulatory Proposal.

Powercor Australia 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 Powercor Australia of the AER's rationale, or the rationale of any of its consultants, for those adjustments. In addition, Powercor Australia 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**

Powercor Australia 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 Powercor Australia'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 Powercor Australia'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 Powercor Australia's debt raising costs;
- the AER's decision regarding the following step changes proposed by Powercor Australia:

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- 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 Powercor Australia's at risk townships 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 Powercor Australia'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 Powercor Australia's proposed materials escalators;
- the AER's decision in respect of Powercor Australia's total capex forecasts;
- 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:
  - to apply Powercor Australia's 2001-05 negative carryover of - \$22.9 million (in \$2004); and
  - on adjustments to the carry over amounts arising in the 2006-10 regulatory period;
- the AER's decision to reject Powercor Australia's proposal that any events that are proposed by Powercor Australia 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 Powercor Australia:
  - recommendations arising from the Bushfires Royal Commission;
  - 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 Powercor Australia's proposed charges for alternative control services (including public lighting).

In this Revised Regulatory Proposal, Powercor Australia 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.

Powercor Australia'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 Powercor Australia's external advisers and additional analysis performed by Powercor Australia.

#### *Recovery of Transmission-related Costs and S factor true up*

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

Powercor Australia 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*). Powercor Australia 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.

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

- increase Powercor Australia'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.

Powercor Australia considers that the AER is required by clause 6.5.6(c) of the Rules to accept this forecast opex, if the AER rejects Powercor Australia'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.

Powercor Australia also maintains that an S factor true up term ( $T_t$ ) should be added to the control mechanism. The AER rejected Powercor Australia'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, Powercor Australia does not agree that the AER has no power to add a term to the WAPC formula. Powercor Australia also does not agree with the AER's proposed method for calculating the S factor true up amount.

In addition, Powercor Australia 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 Powercor Australia in 2010.

### *Growth forecasts*

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

In this Revised Regulatory Proposal, Powercor Australia 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, Powercor Australia 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. Powercor Australia 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.

Powercor Australia 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, Powercor Australia's internal forecasts have been demonstrated historically to have a high degree of accuracy;
- 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 Powercor Australia's Initial Regulatory Proposal;
- reconciling Powercor Australia's internal spatial maximum demand forecasts with these revised NIEIR forecasts of system maximum demand; and
- following this reconciliation, adopting forecasts that were adjusted so they are consistent with NIEIR's revised forecasts of system level maximum demand in Powercor Australia's Current Regulatory Proposal.

Powercor Australia 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*

Powercor Australia 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 Powercor Australia 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, Powercor Australia 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, Powercor Australia maintains that the AER must accept its forecast 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 the implied margins, without adjustment because:

- the opex and capex criteria, properly construed, do not permit the AER to reduce a DNSP's total expenditure forecasts, for example to exclude



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margins under outsourcing arrangements, below the efficient costs of achieving the opex and capex objectives; and

- benchmarking analysis conducted by NERA and SKM establishes that Powercor Australia's forecast opex for 2011-15 set out in its Initial Regulatory Proposal and its unit rates for capital works employed in forecasting capex for 2011-15 in its Initial Regulatory Proposal and this Revised Regulatory Proposal, inclusive of any implied margins 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, are efficiently incurred.

In addition, Powercor Australia 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 Powercor Australia'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, Powercor Australia 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 Powercor Australia'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, Powercor Australia has proposed in this Revised Regulatory Proposal correct adjustments to account for movement in provisions relating to employee entitlements and in respect of capitalisation. Powercor Australia 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.

Powercor Australia 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*

Powercor Australia does not accept the AER's decision in Appendix P of the Draft Determination in respect of debt raising costs. Powercor Australia 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*

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

- 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.

Powercor Australia does not accept the AER's decision to reject its proposed step change in respect of its at risk townships program. Powercor Australia believes in light of community expectations, a prudent operator would undertake works such as its program. The AER has not cited, and Powercor Australia is not aware, of any legislative reason why the AER has to wait until the Victorian Government implements its response to the Bushfires Royal Commission. Indeed, it would appear imprudent of the AER not to consider the program at this time given that the opportunity to mitigate some of the fire risks posed by distribution assets around at risk townships exists today.

In respect of its insurance step change, Powercor Australia proposes to provide the AER with invoices for its actual premiums once they become available in September 2010. Powercor Australia 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, Powercor Australia 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 Powercor Australia'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 Powercor Australia which are not reflected in its base year opex. It is necessary for the AER to allow this step change for Powercor Australia 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, Powercor Australia 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 Powercor Australia's proposal in Chapter 3 of this Revised Regulatory Proposal to amend those requirements).

*Scale escalation*

While Powercor Australia accepts the AER's use of a composite growth factor based on physical metrics as a network growth driver, Powercor Australia 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, Powercor Australia considers that a network growth escalator based on the simple average of growth in line length, transformers and installed zone substation capacity is appropriate.

Powercor Australia 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, Powercor Australia includes in this Revised Regulatory Proposal an updated customer growth escalator, which reflects current customer growth forecasts based on more recent macro economic data.

Powercor Australia 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). Powercor Australia has also adopted the AER's economies of scale adjustment of 50 per cent for the 'Quality audits' opex category (function code 482). However, Powercor Australia maintains that its remaining economies of scale adjustments, and its application of these adjustments, are reasonable.

Powercor Australia 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. Powercor Australia 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 Powercor Australia, 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 Powercor Australia's network, which implies that Powercor Australia's opex should be expected to increase (rather than decrease) in the next regulatory control period. Acting conservatively, however, Powercor Australia 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*

Powercor Australia does not accept the AER's forecasts of labour costs. In particular, Powercor Australia 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, Powercor Australia 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, Powercor Australia 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, Powercor Australia 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, Powercor Australia 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 Powercor Australia will provide the updated forecasts to the AER by 13 September 2010.

*Capex overview*

Powercor Australia does not accept the AER's rejection of its proposed capex forecasts for the next regulatory control period. Powercor Australia submits that the AER's downward adjustment of almost \$580 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 Powercor Australia's proposed capex allowance necessary for the resultant allowance to reasonably reflect the capex criteria.

*Customer connections capex*

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

*Reinforcement capex*

Powercor Australia 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:

- Powercor Australia's internal planning criteria incorporate the same criteria as Powercor Australia's governance documents, which Nuttall Consulting concluded would be expected to deliver prudent and efficient outcomes;
- Powercor Australia's processes take into account synergies and result in forecasts that are economically justified;
- overall, SKM found that Powercor Australia'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 lower than the maximum demand forecasts reconciled with NIEIR's system maximum demand forecast

(presented in Chapter 4) and thus the maximum demand forecasts used for the purposes of forecasting reinforcement capex are conservative and not likely to result in a systematic upward bias in the estimate.

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

Powercor Australia contends that each of the reinforcement projects in the Revised Regulatory Proposal will be required as proposed in the next regulatory control period.

*Reliability and quality maintained capex*

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

Powercor Australia 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 Powercor Australia's forecasts. Removing the two major drivers of the increase in Powercor Australia's forecast in the next regulatory control period (the conductor replacement and reliability programs), which PB considered should be evaluated as step change increases, PB concluded that the variation between the calibrated Repex Model and Powercor Australia's forecasts did not justify an adjustment to Powercor Australia's proposed forecast.

*Environmental, safety and legal capex*

Powercor Australia does not contest the AER's Draft Determination with respect to environmental, safety and legal capex. However, Powercor Australia 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*

While the AER found that Victorian DNSPs have underspent in relation to the ESCV's benchmark allowance for the current regulatory control period, this is not the case for Powercor Australia. On the AER's analysis, Powercor Australia only underspent (relative to the ESCV allowance) by around 8.5 per cent.

The AER has not considered the circumstances of Powercor Australia network in assessing its proposed SCADA and network control capex. Powercor Australia 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*

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

Powercor Australia'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. Powercor Australia does not consider that an event such as the AMI roll-out will occur in the next regulatory control period that would constrain Powercor Australia's non-network – IT capex to the level of its actual expenditure in the current regulatory control period. Powercor Australia 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 Powercor Australia 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, Powercor Australia 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. Powercor Australia rejects the AER's proposition that reinforcement capex deferrals would contribute to the funding of AMI leveraged projects.

Powercor Australia does not consider that the non-network – other capex included in the AER's Draft Determination, an amount significantly less than the historical level of capex, reasonably reflects the capex criteria.

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

Powercor Australia does not accept the AER's decision on the method for calculating the DRP. In particular, Powercor Australia 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 Powercor Australia 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 Powercor Australia's proposed method set out in Chapter 12 of this Revised Regulatory Proposal and an expert report from PwC.<sup>36</sup>
- 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

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<sup>36</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).



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from PwC.<sup>37</sup> 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.

- Based on Powercor Australia's proposed method and a measurement period of the 30 business days from 19 April to 31 May 2010, Powercor Australia 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 Powercor Australia'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<sup>38</sup>.

### *Calculation of estimated cost of corporate income tax*

Powercor Australia 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.

Powercor Australia 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. Powercor Australia considers that the appropriate value for gamma is 0.5 and proposes this gamma value in its Current Regulatory Proposal.

### *Calculation of 2006-10 carry over amounts*

Powercor Australia does not accept the AER's decision to:

- apply Powercor Australia's 2001-05 negative carryover of -\$22.9 million (in \$2004); and
- reject the adjustments to the 2006-10 carry over amounts proposed by Powercor Australia to exclude costs not reflected in the ESCV's opex benchmark (increased vegetation management costs, ATO costs, superannuation costs and GSL payments)<sup>39</sup> and to remove the ESCV's \$5.5 million efficiency adjustment and 0.39 per cent partial productivity factor adjustment.

Powercor Australia has given careful consideration to the AER's legal reasoning in the Draft Determination in support of its view that it has power to apply Powercor Australia's 2001-05 negative carry over of -\$22.9 million (in \$2004). As a result of that consideration, Powercor Australia considers that the AER's

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<sup>37</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).

<sup>38</sup> 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).

<sup>39</sup> Powercor Australia recognises that the AER made an adjustment to the 2006-10 carry over amounts proposed by Powercor Australia for non-recurrent expenditure in 2009 including for certain of the cost categories to which Powercor Australia's proposed adjustments relate (e.g. ATO costs). However, the AER's stated rationale for the making of that adjustment differed from that advanced by Powercor Australia for its proposed adjustments to the 2006-10 carry over amounts and, as a result, the AER confined its adjustments by reference to costs incurred in 2009.

reasoning involves errors of law and affirms its view that the AER has no power to apply Powercor Australia's 2001-05 negative carry over in making its Final Determination.

Powercor Australia does not accept the AER's decision to reject its proposed adjustments to the 2006-10 carry over amounts proposed by Powercor Australia to exclude costs not reflected in the ESCV's opex benchmark (increased vegetation management costs, ATO costs, superannuation costs and GSL payments) and to remove the ESCV's \$5.5 million efficiency adjustment and 0.39 per cent partial productivity factor adjustment. In particular, Powercor Australia 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. Powercor Australia 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
- Powercor Australia 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.

Powercor Australia accepts the AER's proposed adjustments to the 2006-10 carry over amounts in relation to AMI reclassification and related party margins. Powercor Australia 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.

Accordingly, Powercor Australia revises its Initial Regulatory Proposal to update the amount of its proposed adjustment for increased vegetation management costs based on the most recent available information and 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.

*Proposed EBSS excluded cost categories*

Powercor Australia does not accept the AER's rejection of its proposal that any costs related to events proposed by Powercor Australia 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



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- affect revenues and not costs and, therefore, would not affect the EBSS calculation.

Powercor Australia maintains its proposal that the events proposed by Powercor Australia 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 Powercor Australia as nominated pass through events relate to costs and not revenue and will impact the EBSS if they occur.

### *Pass through*

Powercor Australia 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, Powercor Australia 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. Powercor Australia considers that having regard to its annual revenue profile this would result in a materiality threshold for it of \$500,000 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, Powercor Australia 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, Powercor Australia 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.

Powercor Australia 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)*

Powercor Australia 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, Powercor Australia submits that the AER should determine its prices for fee based and quote based alternative control services on the basis that Powercor Australia should be permitted to recover its efficient costs of providing alternative control services. Powercor Australia 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.

Powercor Australia 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.

Powercor Australia 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. Powercor Australia'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, Powercor Australia has identified the key assumptions that underlie the capex and opex forecasts set out in this Revised Regulatory Proposal and two Directors of Powercor Australia 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, Powercor Australia'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 Powercor Australia in its Initial Regulatory Proposal;<sup>40</sup>
- there is no 'Demand management incentive scheme' chapter in this Revised Regulatory Proposal as Powercor Australia 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;
- there is no 'Outcomes monitoring and compliance' chapter as Powercor Australia 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';
- Powercor Australia 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
- Powercor Australia 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).

Powercor Australia has reviewed all of the matters raised by the AER in its Draft Determination including, in particular, where the AER has made adjustments to Powercor Australia's Initial Regulatory Proposal. Powercor Australia has

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<sup>40</sup> AER, Draft Determination, p47.

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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 Powercor Australia 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)

Powercor Australia'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.<sup>41</sup>

Powercor Australia 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, Powercor Australia 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.

Powercor Australia further observes, in response to clause 2.2 of Schedule 1 to the Further RIN, that it does not have anything to produce because Powercor Australia 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 Powercor Australia'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.

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<sup>41</sup> Powercor Australia observes that clause 2.4 of Schedule 1 to the Further RIN would appear to contain a cross-referencing error. Clause 2.4 requires Powercor Australia 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 Powercor Australia 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 Further RIN. Powercor Australia presumes that clause 2.4 should have instead referred to clause 2.3 of Schedule 1 of the Further RIN. Clause 2.3 requires Powercor Australia 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, Powercor Australia 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.

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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:

- 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.

Powercor Australia 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 Powercor Australia as confidential (whether in this Chapter 1, elsewhere in this Revised Regulatory Proposal or in any other document or correspondence provided by Powercor Australia).

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.

Powercor Australia expects that any information in this Revised Regulatory Proposal or the appendices or attachments thereto identified by Powercor Australia as confidential (whether in this Chapter 1, elsewhere in this Revised Regulatory Proposal or in any other document or correspondence provided by Powercor Australia) 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.

Powercor Australia 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 Powercor Australia 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 Powercor Australia's express and specific written consent.



## **2. CLASSIFICATION OF SERVICES**

In this Chapter of the Revised Regulatory Proposal, Powercor Australia 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, Powercor Australia has accepted the AER's classification of services contained in Chapter 2 of its Draft Determination.

In respect of the reserve feeder service, Powercor Australia 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 Powercor Australia observes that it has not varied or departed from the Draft Determination in respect of the classification of a distribution 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



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- if there has been no previous classification, the classification should be consistent with the previously applicable regulatory approach.

### **2.3 Powercor Australia's Initial Regulatory Proposal**

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

In Table 3.2 of its Initial Regulatory Proposal, Powercor Australia 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.

<b>Service</b>	<b>AER's indicative classification in Framework and Approach paper</b>	<b>Powercor Australia's proposed classification</b>
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
Reserve feeder	Not classified	Negotiated Distribution Services
Provision of watchman (security) lights	Not classified	Negotiated Distribution Services
Repair of watchman (security) lights on Powercor Australia 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 160MWh	Alternative Control Service – Fee Based Service	Not regulated
Energisation of new connections	Alternative Control Service – Connection Service	Alternative Control Service – Fee Based Service

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Damage to overhead service cables caused by high load vehicles	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service
High load escort – lifting overhead lines	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service

Table 3.1 Differences between AER's indicative, and Powercor Australia's proposed, services classification

## 2.4 AER's Draft Determination

In the Draft Determination, the AER accepted Powercor Australia'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 Powercor Australia'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;
- 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 Powercor Australia's response to AER's Draft Determination**

Powercor Australia accepts the AER's classification of services contained in Chapter 2 of its Draft Determination. However, 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, Powercor Australia considered that this service should be classified as a negotiated service.<sup>42</sup> In its Draft Determination, the AER decided to classify this service as an alternative control (fee based) service.<sup>43</sup>

Powercor Australia 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 feeder, and does not relate to the request for a new reserve feeder.<sup>44</sup> A request for a new reserve feeder would be treated as for any other new connection under Electricity Guideline 14.

## **2.6 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia has prepared its Revised Regulatory Proposal on the basis of the AER's decision on service classification in its Draft Determination.

In addition, Powercor Australia 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.

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<sup>42</sup> Initial Regulatory Proposal, p23.

<sup>43</sup> AER, Draft Determination, p30.

<sup>44</sup> Initial Regulatory Proposal, p23.

### **3. CONTROL MECHANISM FOR STANDARD CONTROL SERVICES**

In this Chapter of the Revised Regulatory Proposal, Powercor Australia 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**

Powercor Australia 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 Powercor Australia's distribution license and the ESCV's Guideline 15,

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

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

Powercor Australia 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*). If the AER rejects Powercor Australia's proposed WAPC or side constraint terms (or both of them) regarding transmission-related costs, Powercor Australia considers that the AER must:

- increase Powercor Australia'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**

Powercor Australia 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. Powercor Australia 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 ( $T_t$ ).

Powercor Australia 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**

Powercor Australia 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  $K_{Z_t}$  in the maximum transmission revenue control in Appendix F2.5.

### **3.1.4 Appendix E: Changes to tariff structures**

Powercor Australia 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  $q_{t-2}^{ij}$  and  $p_{t-1}^{ij}$ . Powercor Australia 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 Powercor Australia to incur additional costs not contemplated in its Initial Regulatory Proposal.

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

Powercor Australia 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. Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia:

- 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.<sup>45</sup>

### **3.4 AER's Draft Determination**

The WAPC formula set out in the Draft Determination is as follows:<sup>46</sup>

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<sup>45</sup> Initial Regulatory Proposal, pp332-335.

<sup>46</sup> AER, Draft Determination, pp69-70.



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

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";

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

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

$q_{t-2}^{ij}$  is the quantity of component  $j$  of distribution tariff  $i$  that was delivered in regulatory year  $t-2$ ;

$CPI_t$  is calculated as follows:

*'The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the 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;

$S_t$  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:<sup>47</sup>

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<sup>47</sup> AER, Draft Determination, pp70-71.



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

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

$d_t^j$  is the proposed price for component j of the tariff class for year t;

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

$q_{t-2}^j$  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.

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

The AER did not accept Powercor Australia'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.<sup>48</sup>

### **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.<sup>49</sup>

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<sup>48</sup> AER, Draft Determination, pp58-69.

<sup>49</sup> AER, Draft Determination, pp62-66.

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.'*<sup>50</sup>

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.<sup>51</sup> 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.<sup>52</sup>

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.'*<sup>53</sup> 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 Powercor Australia'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.<sup>54</sup>

The AER stated that the DNSPs will instead be able to recover the S factor true-up amount in the 2016-20 Distribution Determination.<sup>55</sup>

### **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.'*<sup>56</sup>

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<sup>50</sup> AER, Draft Determination, p63.

<sup>51</sup> AER, Draft Determination, p64.

<sup>52</sup> AER, Draft Determination, p66.

<sup>53</sup> AER, Draft Determination, p66. The AER made a similar comment specifically in relation to transmission connection charges on p64.

<sup>54</sup> AER, Draft Determination, p59.

<sup>55</sup> AER, Draft Determination, p59.

<sup>56</sup> AER, Draft Determination Appendices, Appendix G, p21.

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 Powercor Australia'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**

Powercor Australia 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.<sup>57</sup> The PFIT Rule Change will allow Powercor Australia 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.<sup>58</sup> However, the timeframes for a rule change mean that there is almost no prospect that a rule 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.

Powercor Australia's Initial Regulatory Proposal did not refer to clause 6.18.7. Powercor Australia 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:

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<sup>57</sup> 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).

<sup>58</sup> 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).

- 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.

Powercor Australia 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.

Powercor Australia 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 Powercor Australia'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.<sup>59</sup>

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:<sup>60</sup>

*'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.<sup>61</sup>

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;<sup>62</sup>

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<sup>59</sup> AER, Draft Determination, p59.

<sup>60</sup> AER, South Australian Draft Determination, Chapter 4 (Control mechanisms for standard control services) (Attachment 21 to this Revised Regulatory Proposal).

<sup>61</sup> AER, South Australian Final Determination, Chapter 4 (Control mechanisms for standard controls services) (Attachment 22 to this Revised Regulatory Proposal), p26.

<sup>62</sup> AER, South Australian Framework and Approach Paper (Attachment 23 to this Revised Regulatory Proposal).

- changed the CPI definition from the definition that was set out in the Framework and Approach Paper; and
- changed the definition of the  $L_t$  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),<sup>63</sup> none of which were provided for in the Queensland Framework and Approach Paper.<sup>64</sup>

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.

Powercor Australia 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.

In light of the above points, Powercor Australia 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. Powercor Australia's proposed formula for calculating the  $TRC_t$  term is set out in Appendix 3.1 of this Revised Regulatory Proposal.

Powercor Australia 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. Powercor Australia incurs Transmission-related Costs as a result of providing direct control network services and complying with regulatory obligations and requirements. Powercor Australia 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.

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<sup>63</sup> AER, Queensland Final Determination, Chapter 4 (Control mechanisms for standard control services) (Attachment 24 to this Revised Regulatory Proposal), p27.

<sup>64</sup> AER, Queensland Framework and Approach Paper (Attachment 25 to this Revised Regulatory Proposal).

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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 Powercor Australia 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	14,146,929	14,262,526	15,029,894	15,181,696	15,335,031	15,489,914	20,591,179
SP Ausnet Augmentation	Connection	2,051,344	6,896,291	9,889,632	9,889,632	9,889,632	9,889,632	4,944,816
Jemena	inter DNSP	3,411,879	3,534,836	3,629,644	3,644,892	3,628,294	3,613,742	3,623,658
Australian Inland Energy	inter DNSP	- 1,252,478	- 1,312,268	0	0	0	0	0
ETSA	inter DNSP	327,319	336,930	345,967	347,420	345,838	344,451	345,396
Avoided TUOS payments <sup>1</sup>	Embedded Generator	803,022	801,362	801,362	842,861	889,902	933,118	972,246
<b>Total Charges</b>		<b>19,488,015</b>	<b>24,519,677</b>	<b>29,696,499</b>	<b>29,906,501</b>	<b>30,088,697</b>	<b>30,270,857</b>	<b>30,477,295</b>

<sup>1</sup> Avoided TuOS payments defined as G payment in chapter 6-10 Rules

<sup>2</sup> Feed In Tariff charges are net of opex

**Table 3.1 Forecast transmission-related costs**

Powercor Australia 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 Powercor Australia's proposed WAPC or side constraint terms (or both of them) regarding Transmission-related Costs.

If the AER rejects those terms, then Powercor Australia 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.<sup>65</sup> Accordingly, Powercor Australia 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.

<sup>65</sup> AER, Draft Determination, p64.



Powercor Australia 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 objectives under clause 6.5.6(a) of the Rules and would be incurred by a prudent operator in Powercor Australia'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 Powercor Australia'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:<sup>66</sup>

*'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).'*

Powercor Australia 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 Powercor Australia'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'*,<sup>67</sup> 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 Powercor Australia and would not have automatically provided a mechanism for it to recover PFIT Payments in the 2011-15 regulatory control period.

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<sup>66</sup> 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.

<sup>67</sup> 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 Powercor Australia 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.<sup>68</sup>

This feed-in tariff event is defined as follows:<sup>69</sup>

*'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.'*

Powercor Australia considers that a similar nominated pass through event must be included in its Final Determination if the AER rejects Powercor Australia'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 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.

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<sup>68</sup> AER, Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), p308.

<sup>69</sup> AER, Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), p311.

Powercor Australia 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 Powercor Australia 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 Powercor Australia.

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. Powercor Australia'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**

Powercor Australia 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, Powercor Australia 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, Powercor Australia 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.

Powercor Australia 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, Powercor Australia 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.

Powercor Australia 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. Powercor Australia's proposed formula for calculating the  $T_t$  term is set out in Appendix 3.1 of this Revised Regulatory Proposal.

Powercor Australia also does not agree with the AER's proposed method for calculating the S factor true up amount. Powercor Australia'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**

Powercor Australia 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.<sup>70</sup> 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. Powercor Australia'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 Powercor Australia 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.<sup>71</sup>

### **3.5.3 Control mechanism formulae**

Powercor Australia 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<sub>t</sub>* factor as follows:

*'passthrough<sub>t</sub> 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.'*<sup>72</sup>

Powercor Australia 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

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<sup>70</sup> ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal).

<sup>71</sup> 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).

<sup>72</sup> AER, Draft Determination, p70.

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. Powercor Australia'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**

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

Accordingly, Powercor Australia 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;

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

$q_{t-2}^{ij}$  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;

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

$q_{t-2}^{cij}$  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);

$p_{t-1}^{ghcij}$  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  $p_{t-1}^{ghcij} = p_{t-1}^{gh}$  for all destination tariffs i and components j. If there is no tariff reassignment then  $g=i$  and  $h=j$ , and  $p_{t-1}^{ghcij} = p_{t-1}^{cij}$ . 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.<sup>73</sup> 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.

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 Powercor Australia'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.<sup>74</sup>

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. Powercor Australia 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*

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<sup>73</sup> AER, Draft Determination Appendices, Appendix E, p14.

<sup>74</sup> AER, Draft Determination Appendices, Appendix E, p18.

*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  $q_{t-2}^{ij}$  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  $q_{t-2}^{ij}$  will not be realistic estimates.

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. Powercor Australia 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.

Powercor Australia considers that this problem can be resolved by amending Appendix E.1 of the Draft Determination so that when determining the value of  $q_{t-2}^{ij}$ , a DNSP is required to adjust the  $q_{t-2}^{ij}$  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. Powercor Australia considers that it is able to estimate the effects of demand responses with reasonable accuracy.

#### **3.5.4.2 Values of $p_{t-1}^{ij}$**

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

Setting the value of  $p_{t-1}^{ij}$  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.

Powercor Australia 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.

Powercor Australia proposes that the AER should amend Appendix E.1 of the Draft Determination to remove the requirement that the value of  $p_{t-1}^{ij}$  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. Powercor Australia expects that these requirements will cause it to incur additional costs that were not contemplated in its Initial Regulatory Proposal.

Powercor Australia'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:<sup>75</sup>

*'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, Powercor Australia 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.

Powercor Australia 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.

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<sup>75</sup> ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), clause 2.1.20.

### **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.

A significant proportion of Powercor Australia'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 noting 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 the 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 for the DNSP to provide notice of tariff assignment.

Powercor Australia receives approximately 35,000 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. Powercor Australia 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. Powercor Australia believes this confusion will lead to customers calling their retailer and/or the DNSP that sent the tariff assignment notice. Powercor Australia 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 Powercor Australia's proposed solution to avoid unnecessary and inefficient costs**

Powercor Australia proposes a way forward that avoids unnecessary costs. In Powercor Australia'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.

Powercor Australia 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 Powercor Australia 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:<sup>76</sup>

*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.*

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<sup>76</sup> 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 Powercor Australia's base year opex.

Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

#### **3.6.1 WAPC formula**

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

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

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;

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

$q_{t-2}^{ij}$  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*);



$p^{ghj}_{t-1}$  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  $p^{ghj}_{t-1} = p^{gh}_{t-1}$  for all destination tariffs i and components j. If there is no tariff reassignment then  $g=i$  and  $h=j$ , and  $p^{ghj}_{t-1} = p^{ij}_{t-1}$ );

$q^{ghj}_{t-2}$  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

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

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

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.);

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

$q_{t-2}^{cij}$  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*);

$p_{t-1}^{ghcij}$  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  $p_{t-1}^{ghcij} = p_{t-1}^{gh}$  for all destination tariffs *i* and components *j*. If there is no tariff reassignment then *g*=*i* and *h*=*j*, and  $p_{t-1}^{ghcij} = p_{t-1}^{cij}$ . Note also that source tariff *g* and source component *h* are not necessarily of class *c*.);

$q_{t-2}^{ghcij}$  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**

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

- increase Powercor Australia'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**

Powercor Australia 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.*

Powercor Australia 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 Powercor Australia 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, Powercor Australia responds to Chapter 5 of the AER's Draft Determination regarding Powercor Australia'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**

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

In this Revised Regulatory Proposal, Powercor Australia 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, Powercor Australia 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. Powercor Australia 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**

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

Powercor Australia 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, Powercor Australia's internal spatial demand forecasts have been demonstrated historically to have a high degree of accuracy;
- 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 Powercor Australia's Initial Regulatory Proposal);
- reconciling Powercor Australia's internal spatial maximum demand forecasts with these revised NIEIR forecasts of system maximum demand; and

- adopting adjusted maximum demand forecasts that are consistent with NIEIR's updated forecasts of system maximum demand.

#### **4.1.3 Customer numbers forecasts**

Powercor Australia 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**

Powercor Australia 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 Powercor Australia'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, Powercor Australia 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:<sup>77</sup>

*'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 Powercor Australia. For example, given:

- Powercor Australia'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 Powercor Australia 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

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<sup>77</sup> AER, Draft Determination, p73.

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 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia 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 Powercor Australia region to 2019.<sup>78</sup>

#### **4.3.2 AER's Draft Determination**

The AER rejected the energy consumption forecasts included in Powercor Australia'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 Powercor Australia's energy consumption forecasts.<sup>79</sup> The reasons for the AER's rejection of Powercor Australia'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.<sup>80</sup> The AER considered that NIEIR's industry based approach to forecasting energy 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.<sup>81</sup>

##### **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.

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<sup>78</sup> Attachment P0005 to the Initial Regulatory Proposal.

<sup>79</sup> AER, Draft Determination, p84.

<sup>80</sup> AER, Draft Determination, pp98-9.

<sup>81</sup> AER, Draft Determination, p98.



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*'.<sup>82</sup> ACIL Tasman recommended that NIEIR's population growth forecasts be replaced with the ABS' 'B series' population forecasts.<sup>83</sup> The AER agreed.<sup>84</sup>

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.<sup>85</sup>

#### **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.<sup>86</sup>

In addition, based on ACIL Tasman's recommendations, the AER removed the post model adjustments made by NIEIR for four policies:<sup>87</sup>

- 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.

##### *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.<sup>88</sup>

##### *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.<sup>89</sup> ACIL Tasman noted that its conclusion was '*strengthened by the fact that a*

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<sup>82</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp13-4.

<sup>83</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp13-4, and 80.

<sup>84</sup> AER, Draft Determination, p156.

<sup>85</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p89; AER, Draft Determination, p156.

<sup>86</sup> AER, Draft Determination, pp116-17, and 156.

<sup>87</sup> 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.

<sup>88</sup> AER, Draft Determination, pp120-1.

<sup>89</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp30-1.

*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.*<sup>90</sup> The AER adopted ACIL Tasman's recommendation.<sup>91</sup>

#### *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.<sup>92</sup> 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).<sup>93</sup> The AER agreed and adopted ACIL Tasman's recommendation in its Draft Determination.<sup>94</sup>

#### *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.<sup>95</sup> 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.'*<sup>96</sup>

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 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:<sup>97</sup>

- 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.

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<sup>90</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p31.

<sup>91</sup> AER, Draft Determination, p120.

<sup>92</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p28.

<sup>93</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p26.

<sup>94</sup> AER, Draft Determination, p114.

<sup>95</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p56.

<sup>96</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p56.

<sup>97</sup> AER, Draft Determination, pp148-55.

### **4.3.3 Powercor Australia's response to the AER's Draft Determination**

#### **4.3.3.1 Summary**

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

Pursuant to the Draft Determination, Powercor Australia 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 Powercor Australia region to 2019<sup>98</sup>, June 2010. Powercor Australia submits these forecasts are appropriate.

Powercor Australia 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 Powercor Australia's energy consumption forecasts.<sup>99</sup> Powercor Australia'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. Powercor Australia 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
- 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.

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

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<sup>98</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p85 (Table 7.1).

<sup>99</sup> AER, Draft Determination, p84.

#### **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, Powercor Australia 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 Powercor Australia, April 2010.

The AER indicated in its Draft Determination that, given the time available, it had not considered the additional information provided by Powercor Australia for the purposes of the Draft Determination but would consider it in making its Final Determination.<sup>100</sup>

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

Frontier was engaged by Powercor Australia to assess the reasonableness of the methodology used by NIEIR to prepare its energy consumption forecasts.<sup>101</sup> Frontier concluded that the capabilities of NIEIR's modelling system meet world best practice standards.<sup>102</sup> 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 sound.<sup>103</sup> 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

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<sup>100</sup> AER, Draft Determination, p94.

<sup>101</sup> 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 Powercor Australia 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).

<sup>102</sup> Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010 (provided to the AER by email on 28 April 2010), p.ii.

<sup>103</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p10.

- 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.<sup>104</sup> This is consistent with the ABS' 'series B' population forecast that ACIL Tasman recommended for use in forecasting energy consumption.<sup>105</sup>

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 Powercor Australia's energy consumption forecasts reflected in this Revised Regulatory Proposal.

Powercor Australia 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');<sup>106</sup> and
- the methodology adopted by ACIL Tasman for estimating the impact of the increase in population growth is flawed.

Powercor Australia 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 from the workbook provided to Powercor Australia by the AER.<sup>107</sup> Frontier found that ACIL Tasman's approach to estimating the impact was flawed primarily because ACIL Tasman assumes a constant per capita energy use.<sup>108</sup> As was acknowledged by ACIL Tasman, this does not account for:<sup>109</sup>

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

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<sup>104</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p28.

<sup>105</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp13-4.

<sup>106</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15; ACIL Tasman, population adjustment spreadsheet (provided to Powercor Australia by the AER by email on 16 June 2010).

<sup>107</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15; ACIL Tasman, population adjustment spreadsheet (provided to Powercor Australia by the AER by email on 16 June 2010).

<sup>108</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15.

<sup>109</sup> 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.

- 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.<sup>110</sup> Specifically, ACIL Tasman's approach does not test or validate its results.<sup>111</sup>

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.<sup>112</sup> 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 Powercor Australia's Revised Regulatory Proposal, reflect GSP forecasts that take into account recent economic conditions.<sup>113</sup>

While in November 2009 NIEIR considered there would be relatively slow economic growth virtually across the entire period in Victoria in 2011-15,<sup>114</sup> 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.<sup>115</sup>

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

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<sup>110</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p15.

<sup>111</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p16.

<sup>112</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp14-5.

<sup>113</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), pp26-30.

<sup>114</sup> NIEIR, Electricity sales and customer number projections for the Powercor Australia region to 2019, November 2009 (Attachment P0005 to the Initial Regulatory Proposal), p21.

<sup>115</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p28.



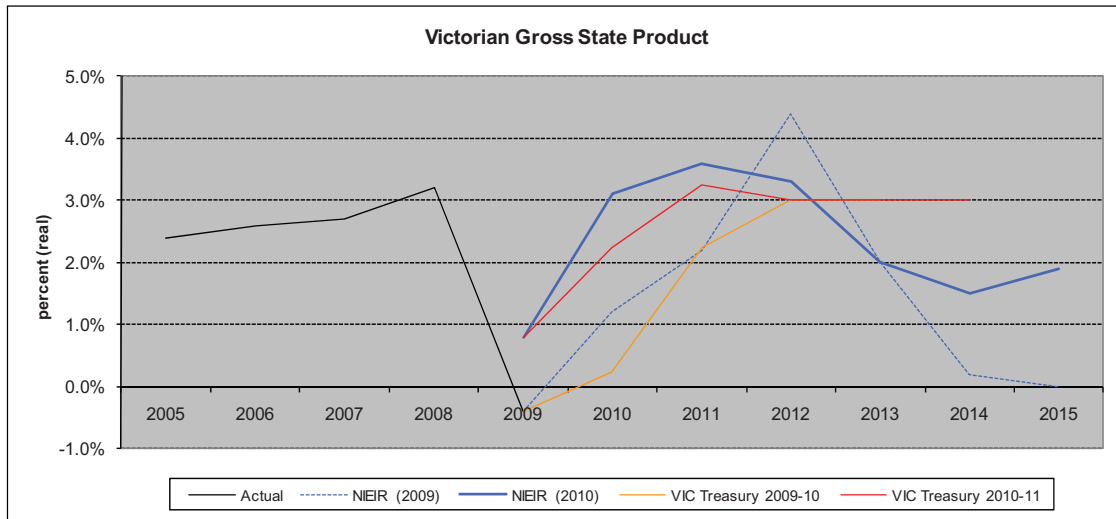


Figure 4.1 Forecasts of Victorian GSP by NIEIR and the Victorian Treasury

#### 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.<sup>116</sup>

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', Powercor Australia assumes the AER intended the delay to be until 1 January 2013. NIEIR's updated energy consumption forecasts reflect this.<sup>117</sup> 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.

Powercor Australia submits that these adjustments are appropriate. This is demonstrated by Frontier's Review of policy adjustments, June 2010.<sup>118</sup> Powercor Australia engaged Frontier to estimate the expected impact on energy consumption in the next regulatory control period of Government policies designed to address climate change and energy efficiency. Frontier's conclusions regarding the appropriate level of post model adjustments is also set out in Figure 4.2 below.

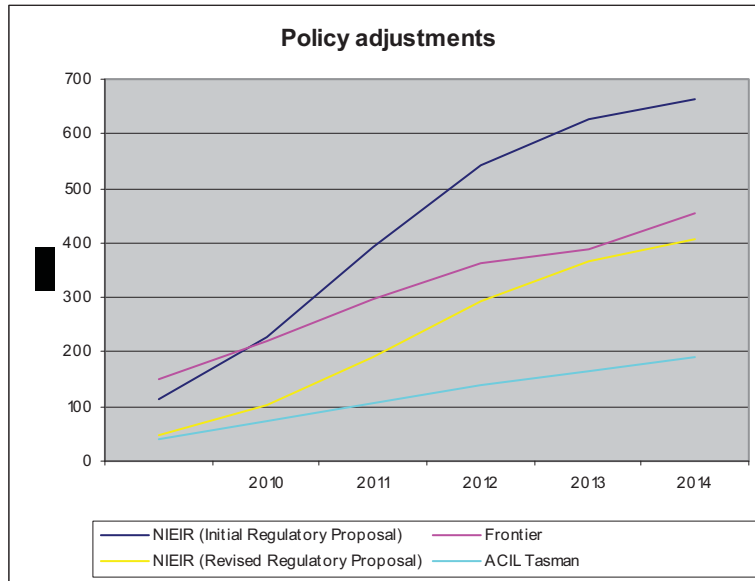
Figure 4.2 shows that the overall level of post model adjustments to energy consumption estimated by NIEIR (in its June 2010 report) and the level estimated by Frontier are consistent. Given this represents the views of two independent experts, Powercor Australia submits that, on the evidence before it, the AER

<sup>116</sup> Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010 (provided to the AER by email on 28 April 2010), p7.

<sup>117</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p9.

<sup>118</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal),

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**

Powercor Australia 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.<sup>119</sup>

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.<sup>120</sup>

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 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, Powercor Australia 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.

<sup>119</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p ix.

<sup>120</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, Final report, 21 April 2010, p37.

*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, Powercor Australia 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.<sup>121</sup> 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.<sup>122</sup> 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<sup>123</sup> by the time of the cancellation of the program, justifies an adjustment to take into account some impact on energy consumption from the program.<sup>124</sup>

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 Powercor Australia) 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 Powercor Australia 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.<sup>125</sup>

*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.<sup>126</sup> Frontier reached its conclusion as follows:<sup>127</sup>

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<sup>121</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), pp62-3.

<sup>122</sup> 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.

<sup>123</sup> Hawke, A, Hawke Report, Review of the Administration of the Home Insulation Program, 6 April 2010 (Attachment 57 to this Revised Regulatory Proposal), p24.

<sup>124</sup> 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).

<sup>125</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2010, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p68; Frontier, Review of policy adjustments, June 2010 (Attachment 36 to this Revised Regulatory Proposal), pp55-6.

<sup>126</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p49.

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- In 2000, all Australian jurisdictions (through the MCE) endorsed the International Energy Agency's one watt program for standby power.<sup>128</sup>
- The MCE's strategy involved a two stage process:<sup>129</sup>
  - 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.<sup>130</sup> In addition, Powercor Australia 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.<sup>131</sup>

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, Powercor Australia observes that NIEIR has recognised existing standby targets in preparing its energy consumption forecasts.<sup>132</sup>

Similarly, in preparing its forecast of the impact, Frontier excluded the contribution to energy savings of air conditioners and televisions.<sup>133</sup> It did so because these appliances are already subject to MEPS.<sup>134</sup>

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<sup>127</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p49.

<sup>128</sup> MCE, Money Isn't All You're Saving, Australia's standby power strategy 2002-2012, 2002 (Attachment 38 to this Revised Regulatory Proposal).

<sup>129</sup> 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.

<sup>130</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p9.

<sup>131</sup> 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.

<sup>132</sup> NIEIR, Electricity sales and customer numbers projections for the Powercor Australia region to 2019, November 2009 (Attachment P0005 to the Initial Regulatory Proposal), p55; NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p62.

<sup>133</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p52.

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 Powercor Australia 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).<sup>135</sup>

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.<sup>136</sup> 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.<sup>137</sup>

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 Powercor Australia for lighting MEPS in this Revised Regulatory Proposal is appropriate.

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.

Powercor Australia 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

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<sup>134</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p52.

<sup>135</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), pp9-11; Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), pp34-6.

<sup>136</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p11.

<sup>137</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), pp11-2.



forecasting the likely impact of VEET.<sup>138</sup> 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*

Powercor Australia 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. Powercor Australia 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:<sup>139</sup>

- 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.

Powercor Australia 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.<sup>140</sup> 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*',<sup>141</sup> 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.<sup>142</sup> Further, in response to the AER's comment that NIEIR did not consider certain papers discussed in the primary report relied on by NIEIR (the Brattle Group study),<sup>143</sup> Powercor Australia notes that this study is a survey of recent experiments.<sup>144</sup> That is, NIEIR relied on this report rather than conducting its own assessment of each of the underlying surveys. Powercor Australia submits this is entirely appropriate.

Regarding the uncertainty around the introduction of TOU Tariffs, Powercor Australia 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

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<sup>138</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p37.

<sup>139</sup> AER, Draft Determination, pp148-55.

<sup>140</sup> AER, Draft Determination, pp148-9.

<sup>141</sup> AER, Draft Determination, p149.

<sup>142</sup> ACIL Tasman, Review of maximum demand forecasts, 19 April 2010, p40; AER, Draft Determination, p149.

<sup>143</sup> AER, Draft Determination, p149.

<sup>144</sup> NIEIR, Maximum summer demand forecasts for Powercor Australia 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.



Resources regarding his request for a deferral of TOU Tariffs, the Minister only requested that the introduction be deferred until 2011.<sup>145</sup>

Powercor Australia intends to move to TOU Tariffs in the next regulatory control period. This can be seen from Powercor Australia's presentation to retailers on 13 July 2010, which contemplates introduction of TOU Tariffs in January 2011.<sup>146</sup>



Powercor Australia notes that NIEIR assumes that TOU Tariffs will be introduced in 2013.<sup>149</sup> 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.<sup>150</sup> Frontier concludes, based on its review of several studies, that even a partial take-up of TOU Tariffs should deliver most of the energy savings from such a pricing structure.<sup>151</sup>

Accordingly, even if TOU Tariffs are not made compulsory in the next regulatory control period, Powercor Australia 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:

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<sup>145</sup> 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.

<sup>146</sup> 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.

<sup>147</sup> 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.

<sup>148</sup> DPI, Presentation to AMI Policy Committee, 29 June 2010 (Attachment 55 to this Revised Regulatory Proposal), slides 2, 5-7.

<sup>149</sup> NIEIR, Energy consumption and customer numbers for the Powercor Australia region to 2019, June 2010, p73.

<sup>150</sup> 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.

<sup>151</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p24.

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- the inability of DNSPs to send price signals to customers, including because of:
  - the proportion of the total bill that distribution charges make up;<sup>152</sup> 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;<sup>153</sup>
- the inability of customers to respond to TOU tariffs due to their personal circumstances, particularly in the short term;<sup>154</sup>
- inelastic demand for electricity in the short run;<sup>155</sup>
- 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;<sup>156</sup>
- 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;<sup>157</sup> and
- the rebound effect.<sup>158</sup>

Powercor Australia acknowledges that DNSPs’ charges only constitute a part of the end price paid by consumers. However, Powercor Australia does not consider that this prevents DNSPs from sending price signals to consumers. Powercor Australia 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.<sup>159</sup> Thus, the results of the trials relied on by NIEIR and Frontier

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<sup>152</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp51-52.

<sup>153</sup> AER, Draft Determination, p151.

<sup>154</sup> AER, Draft Determination, p151; ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, p54.

<sup>155</sup> 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.

<sup>156</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, 21 April 2010, pp48-9.

<sup>157</sup> 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. Powercor Australia 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.

<sup>158</sup> AER, Draft Determination, pp151-2; ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p42.

<sup>159</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p5.

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.

Powercor Australia 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.

Powercor Australia observes that the AER has not provided any evidence of retailers seeking to charge consumers consistent prices. To the contrary, Powercor Australia notes that retailers publish different tariffs, depending on the distribution region.<sup>160</sup>

Powercor Australia 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.<sup>161</sup> 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).<sup>162</sup> 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).<sup>163</sup> As noted by Frontier, 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.<sup>164</sup> The California Statewide Pricing Pilot is therefore not a strong basis for disregarding expected reductions in energy consumption.<sup>165</sup> ACIL

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<sup>160</sup> 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).

<sup>161</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p24.

<sup>162</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), pp5-6.

<sup>163</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p6.

<sup>164</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p6.

<sup>165</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p6.

Tasman also relies on the California Statewide Pricing Pilot to support its statements regarding the relativity effect.<sup>166</sup> Accordingly, Powercor Australia 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.<sup>167</sup> 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.<sup>168</sup> 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.<sup>169</sup> ACIL Tasman indicates that this is because:<sup>170</sup>

- 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.<sup>171</sup> 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.<sup>172</sup> Given 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, Powercor Australia 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

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<sup>166</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p42.

<sup>167</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p5.

<sup>168</sup> Frontier, Review of ACIL Tasman recommendations, June 2010 (Attachment 37 to this Revised Regulatory Proposal), p5.

<sup>169</sup> AER, Draft Determination, pp151-152; ACIL Tasman, Review of maximum demand forecasts, 19 April 2010, p42.

<sup>170</sup> AER, Draft Determination, pp151-152; ACIL Tasman, Review of maximum demand forecasts, 19 April 2010, p42.

<sup>171</sup> Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010, p18.

<sup>172</sup> Frontier, Review of NIEIR's methodology for forecasting electricity consumption, April 2010, p18.

reduction in energy consumption due to TOU Tariffs is eight per cent.<sup>173</sup> 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.<sup>174</sup>

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.<sup>175</sup> 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.<sup>176</sup> Frontier considered therefore that it was reasonable to assume that some benefits of IHDs could potentially be realised.<sup>177</sup>

Finally, Powercor Australia 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.<sup>178</sup> It allows users to view their energy consumption from anywhere online.<sup>179</sup> Google PowerMeter:<sup>180</sup>

- 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

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<sup>173</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p72.

<sup>174</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p73.

<sup>175</sup> AER, Draft Determination, p151.

<sup>176</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p23.

<sup>177</sup> Frontier, Review of policy adjustments, July 2010 (Attachment 36 to this Revised Regulatory Proposal), p23.

<sup>178</sup> 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](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](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).

<sup>179</sup> What is Google PowerMeter, available at <http://www.google.com/powermeter/about/about.html> (Attachment 58 to this Revised Regulatory Proposal).

<sup>180</sup> What is Google PowerMeter, available at <http://www.google.com/powermeter/about/about.html> (Attachment 58 to this Revised Regulatory Proposal).



consumption in the next regulatory control period, regardless of whether TOU Tariffs are introduced.

Given the above, Powercor Australia 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 Powercor Australia in this Revised Regulatory Proposal.

#### **4.3.3.5 Alternative energy consumption forecasts**

In the event the AER seeks to adjust Powercor Australia'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.<sup>181</sup>

However, VENCORP's forecasts are now significantly out of date and do not reflect recent economic conditions. Further, Powercor Australia 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, 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	10,148	10,299	10,510	10,579	10,876	1.40%
Revised Regulatory Proposal	10,148	10,299	10,510	10,491	10,585	1.11%
	2011	2012	2013	2014	2015	2010-15
Draft Determination	11,163	11,463	11,764	11,994	12,151	2.24%
Revised Regulatory Proposal	10,718	10,763	10,712	10,666	10,691	0.20%

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

<sup>181</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p8.



#### **4.3.4 Powercor Australia's Revised Regulatory Proposal**

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

	2011	2012	2013	2014	2015
Energy consumption (GWh)	10,718	10,763	10,712	10,666	10,691

Table 4.2 Energy consumption forecasts in the Revised Regulatory Proposal

### **4.4 Maximum demand forecasts**

#### **4.4.1 Powercor Australia's Initial Regulatory Proposal**

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

In its review of Powercor Australia's policies, practices, procedures and governance arrangements, the independent expert, PB concluded that Powercor Australia's approach to forecasting demand is appropriate and reasonable given the relatively low growth of network demand.<sup>182</sup> Powercor Australia 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.

Powercor Australia also submitted with its Initial Regulatory proposal system level maximum demand forecasts prepared by NIEIR.<sup>183</sup> However, as noted in material provided by Powercor Australia to the AER subsequent to the Initial Regulatory Proposal, Powercor Australia did not seek to identify errors in the report submitted.<sup>184</sup>

#### **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.<sup>185</sup> The AER considered such a top down reconciliation to be fundamental to producing reasonable spatial demand forecasts.<sup>186</sup>

While acknowledging actual maximum demand in 2006-08 may have been affected by the onset of the GFC, the AER indicated that, on average, Powercor Australia's forecasts exceeded actual maximum demand by 13 per cent over 2006-08.<sup>187</sup>

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<sup>182</sup> PB, Review of Powercor's policies, practices, procedures and governance arrangements, October 2009 (Attachment P0042 to Powercor Australia's Initial Regulatory Proposal), pp7-8 and 11.

<sup>183</sup> NIEIR, Maximum demand forecasts for Powercor Australia terminal stations to 2019, November 2009 (Attachment P006 to the Initial Regulatory Proposal).

<sup>184</sup> Powercor Australia, Maximum Demand forecasting – Questions for Powercor Australia (PC) Responses requested by 12 February 2009 (provided to the AER by email on 17 February 2010), p2.

<sup>185</sup> AER, Draft Determination, p92.

<sup>186</sup> AER, Draft Determination, pp122 and 133.

<sup>187</sup> AER, Draft Determination, p81 (Table 5.7).

In describing Powercor Australia's spatial demand forecasting methodology, ACIL Tasman stated:<sup>188</sup>

*'Powercor has asserted that peak demand in its area is generally driven by water pumping. This makes Powercor's area unique among the Victorian distribution businesses as each of the others faces peak demand that is drive by temperature sensitive load, mainly air-conditioners.'*

The AER rejected Powercor Australia's proposed maximum demand forecasts and substituted the maximum demand forecasts recommended by ACIL Tasman.<sup>189</sup>

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

#### **4.4.3 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia does not accept the AER's forecasts of maximum demand, substituted in the AER's Draft Determination for those in its Initial Regulatory Proposal. Powercor Australia 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, Powercor Australia's internal spatial demand forecasts have been demonstrated historically to have a high degree of accuracy;
- 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 Powercor Australia's Initial Regulatory Proposal);
- reconciling Powercor Australia's internal spatial maximum demand forecasts with these revised NIEIR forecasts of system maximum demand; and
- adopting adjusted maximum demand forecasts that are consistent with NIEIR's updated forecasts of system maximum demand.

##### **4.4.3.1 Spatial maximum demand forecasts**

Powercor Australia 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.<sup>190</sup>

Powercor Australia notes that the AER erred in its calculation of the difference between forecast and actual maximum demand.<sup>191</sup> The peak demand forecasts

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<sup>188</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p68.

<sup>189</sup> AER, Draft Determination, pp132-3 and 155-6.

<sup>190</sup> AER, Draft Determination, p74.

<sup>191</sup> AER, Draft Determination, p81 (Table 5.7). Details of the calculation were provided to Powercor Australia by the AER by email on 16 June 2010.

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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.<sup>192</sup> The forecasts included in the ESCV's 2006-10 EDPR were in fact the sum of the feeder peak demands Powercor Australia submitted to the ESCV.<sup>193</sup> 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, Powercor Australia's forecasts for 2006-08 zone substation maximum demand were **below** the actual level over the period. As shown in Table 4.3 below, the actual maximum demand (unadjusted for weather) in Powercor Australia's zone substations in the period 2006-10 was, on average, 104.3 per cent of its forecast.

Total ZSS maximum demand (MW)	2006	2007	2008	2009	2010
Forecast (50% PoE) <sup>194</sup>	2,045	2,101	2,155	2,204	2,254
Actual (unadjusted for weather) <sup>195</sup>	2,073	2,148	2,244	2,347	2,330
Actual relative to forecast	101.4%	102.2%	104.1%	110.6%	103.4%

**Table 4.3 Powercor Australia's zone substation maximum demand forecasts relative to actual maximum demand**

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

Further, Powercor Australia's 2010 actual maximum demand figures are consistent with the maximum demand forecasts included in the Initial Regulatory Proposal. Powercor Australia's total forecast zone substation maximum demand

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<sup>192</sup> The AER indicated in an email from Lawrence Irlam to Powercor Australia on 16 June 2010 that it relied on the forecasts 'from the ESCV's determination (table 4.3 on page 133 of its determination)'.

<sup>193</sup> Templates 10(b) to 10(e) submitted to the ESCV in the 2006-10 EDPR process by Powercor Australia, 12 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.

<sup>194</sup> Templates 10(c) to 10(f) submitted to the ESCV in the 2006-10 EDPR process by Powercor Australia, 12 November 2004 (Attachment 48 to this Revised Regulatory Proposal).

<sup>195</sup> See Revised Regulatory Template 6.3. Powercor Australia notes that it only has temperature adjusted actual maximum demand data at the zone substation level for 2010 (and not for preceding years).

was 2254 MW in 2010, while actual maximum demand was 2330 MW (103 per cent of the forecast).<sup>196</sup>

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

Powercor Australia 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 Powercor Australia, 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.<sup>197</sup>

Finally, for completeness, Powercor Australia notes that ACIL Tasman's assertion that Powercor Australia indicated that maximum demand in its distribution area is generally driven by water pumping is incorrect.<sup>198</sup> Rather, what Powercor Australia indicated in discussions with ACIL Tasman was that the maximum demand of some rural zone substations was subject to the variability of water pumping load.

#### **4.4.3.2 Top down reconciliation**

The AER's top down reconciliation of Powercor Australia'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, Powercor Australia has conducted a top-down reconciliation of its internal spatial demand forecasts with NIEIR's updated system maximum demand forecasts and adjusted its internally prepared spatial demand forecasts so that they are consistent with NIEIR's updated forecasts of maximum demand.

##### *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

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<sup>196</sup> Revised Regulatory Template 6.3 (Tables 11 and 21). Powercor Australia 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').

<sup>197</sup> SKM, CitiPower/Powercor Demand Forecasts, 8 July 2010 (Attachment 50 to this Revised Regulatory Proposal), p34.

<sup>198</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p68.

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Proposal.<sup>199</sup> Powercor Australia 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 recent events related to recorded 2009 maximum demand (which forms the starting point for the 2010-15 forecasts):

- rearrangement of 66kV supply point (BLTS-BHM);
- rearrangement of 66kV supply point data (ATS-WBE); and
- commissioning of a small embedded generator in the Shepparton area.

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 4.4 below.

	MW
NIEIR November 2009 recorded system maximum demand	2,299
Recent rearrangement of 66kV supply point (BLTS-BHM)	29
Recent rearrangement of 66kV supply point (ATS-WBE)	41
Recently commissioned small embedded generator in the Shepparton area	1
Net HV feeder cross boundary supply to other DNSPs	7
Updated NIEIR Powercor Australia 2009 system maximum demand	2,377

**Table 4.4 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.<sup>200</sup> 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, Powercor Australia 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.<sup>201</sup>

<sup>199</sup> NIEIR, Maximum summer demand forecasts for Powercor Australia to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal).

<sup>200</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, 19 April 2010, p19.

<sup>201</sup> 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 Powercor Australia did not rely on NIEIR's forecasts of maximum demand in preparing its Initial Regulatory Proposal, Powercor Australia did not engage Frontier to prepare a similar report in respect of NIEIR's maximum demand forecasting methodology.

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.

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,<sup>202</sup> 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.<sup>203</sup>

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.<sup>204</sup>

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:<sup>205</sup>

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

Powercor Australia considers that each of these adjustments reflected in NIEIR's revised forecasts are reasonable.<sup>206</sup> 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

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<sup>202</sup> NIEIR, Maximum summer demand forecasts for Powercor Australia to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), p21.

<sup>203</sup> NIEIR, Maximum summer demand forecasts for Powercor Australia to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), pp2-28.

<sup>204</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), p9.

<sup>205</sup> 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.

<sup>206</sup> Powercor Australia 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 primarily on NIEIR's forecasts in preparing its Initial Regulatory Proposal.



accounted for). NIEIR has recognised existing standby targets in preparing its maximum demand forecasts.<sup>207</sup>

- It is reasonable to assume that TOU Tariffs will be introduced by Powercor Australia 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.<sup>208</sup> 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, Powercor Australia rejects the AER's assertion that NIEIR was inconsistent in its assessment of the impact of TOU Tariffs on energy consumption and maximum demand.

Powercor Australia 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. Powercor Australia's TOU Tariffs would likely spread the peak period across five or six hours.<sup>209</sup> 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. Powercor Australia 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:<sup>210</sup>

*'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 of 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. Powercor Australia 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 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

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<sup>207</sup> NIEIR, Maximum summer demand forecasts for Powercor Australia to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), p44.

<sup>208</sup> NIEIR, Maximum summer demand forecasts for Powercor Australia to 2020, June 2010 (Attachment 43 to this Revised Regulatory Proposal), p55.

<sup>209</sup> 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.

<sup>210</sup> AER, Draft Determination, p149.

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weather than TOU Tariffs. Powercor Australia 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 Powercor Australia 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 Powercor Australia's maximum demand forecasts, CitiPower / Powercor Demand Forecasts, 8 July 2010, confirm if a reasonably reliable ratio can be established between the historical non-coincident zone substation maximum demands and Powercor Australia'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, 0.9403 with a 90 per cent confidence interval of +/-0.048 (i.e. a range of 0.8923 to 0.9883).<sup>211</sup>

The zone substation non-coincident forecasts from the Initial Regulatory Proposal were found to be outside the 90 per cent confidence levels established by SKM. NIEIR's forecasts indicated that Powercor Australia's zone substation forecasts were lower than they should be.

Accordingly, Powercor Australia adjusted its zone substation non-coincident forecasts to ensure the ratios with NIEIR's updated system level forecasts were within the 90 per cent confidence interval established by SKM. Individual zone substation adjustments were made by Powercor Australia as follows:

- The selected zone substations were identified from known high commercial and residential growth areas, where load growth is forecast to continue due to local economic development and government support. These areas include the growth corridor in the outer western suburbs of Melbourne, and

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<sup>211</sup> SKM, CitiPower/Powercor Demand Forecasts, 8 July 2010 (Attachment 50 to this Revised Regulatory Proposal), p23.

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growth corridors in Geelong (including the Armstrong Creek major subdivision), Ballarat, Shepparton and Bendigo.

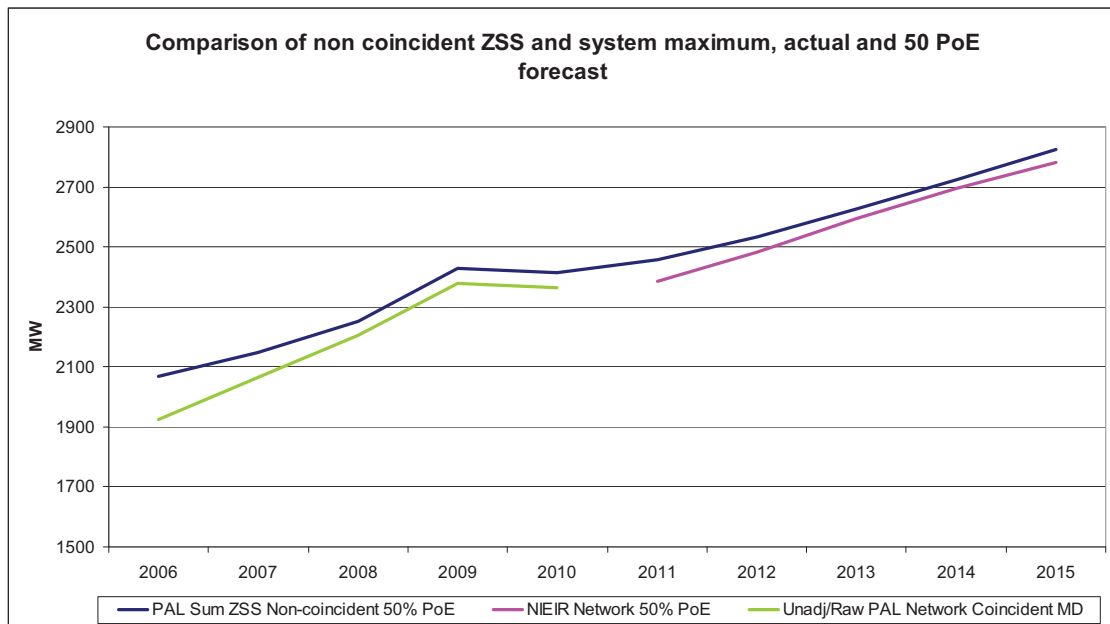
- The non-coincident load forecast was then increased by a small percentage on these targeted zone substations until the summated non-coincident zone substation forecast was within the 90 per cent confidence level.
- The adjusted non-coincident forecasts were then checked to confirm the new load growth was reasonable.

Powercor Australia's revised maximum spatial demand forecasts (including the adjustments made following the reconciliation with NIEIR's updated system peak demand forecasts) are shown in Appendix 4.1. The final ratios (based on Powercor Australia's adjusted maximum demand forecasts) are shown in Table 4.5 below. Table 4.5 shows that Powercor Australia's ratios are well within the 90 per cent confidence interval established by SKM.

50% PoE Forecasts (MW)	2011	2012	2013	2014	2015
NIEIR system <sup>212</sup>	2,385	2,483	2,596	2,695	2,780
Powercor Australia one substation non-coincident <sup>213</sup>	2,457	2,532	2,627	2,722	2,823
Ratio	0.971	0.981	0.988	0.990	0.985

**Table 4.5 Reconciliation of NIEIR system maximum demand forecasts and Powercor Australia's non-coincident maximum demand forecasts, 50% PoE**

The forecasts from Table 4.5 are illustrated in Figure 4.3 below, together with actual maximum demand from 2006-10.



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

<sup>212</sup> Revised Regulatory Template 6.3 (Table 12).

<sup>213</sup> Revised Regulatory Template 6.3 (Table 21).

#### **4.4.4 Powercor Australia's Revised Regulatory Proposal**

The maximum demand forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 4.6 below.

	2011	2012	2013	2014	2015
Maximum demand (MW)	2,481	2,557	2,652	2,747	2,848

Table 4.6 Maximum demand forecasts included in the Revised Regulatory Proposal

### **4.5 Customer number forecasts**

#### **4.5.1 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia adopted the customer number forecasts prepared by NIEIR which are set out in the report entitled *Electricity sales and customer number projections for the Powercor Australia region to 2019*.<sup>214</sup>

Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal.<sup>215</sup>

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.<sup>216</sup>

The AER found that NIEIR's forecasts predict a continuation of recent historical trends, which the AER considered was reasonable.<sup>217</sup> The AER went on, however, to state that:<sup>218</sup>

*'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 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia's Revised Regulatory Proposal reflects the updated forecasts prepared by NIEIR, which are set out in its report, *Electricity sales and customer*

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<sup>214</sup> Attachment P0005 to the Initial Regulatory Proposal.

<sup>215</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, Final report, 11 May 2010, pp58-9.

<sup>216</sup> ACIL Tasman, Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, Final report, 11 May 2010, p59.

<sup>217</sup> AER, Draft Determination, p99.

<sup>218</sup> AER, Draft Determination, p99. The AER reiterated its position on page 156 of the Draft Determination.

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number projections for the Powercor Australia region to 2019, June 2010.<sup>219</sup> Powercor Australia 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:

- 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 Powercor Australia's Revised Regulatory Proposal

The customer numbers forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 4.7 below.

	2011	2012	2013	2014	2015
Customer numbers	717,745	731,603	745,570	759,343	772,544

Table 4.7 Customer numbers forecasts included in the Revised Regulatory Proposal

## 4.6 Powercor Australia's Revised Regulatory Proposal

In preparing its Revised Regulatory Proposal, Powercor Australia has used the forecasts of energy consumption, maximum demand and customer numbers set out in Table 4.8.

	2011	2012	2013	2014	2015
Energy consumption (GWh)	10,718	10,763	10,712	10,666	10,691
Maximum demand (MW) <sup>220</sup>	2,481	2,557	2,652	2,747	2,848
Customer numbers	717,745	731,603	745,570	759,343	772,544

Table 4.8 Powercor Australia's energy consumption, maximum demand and customer numbers forecasts for 2011-15 included in the Revised Regulatory Proposal

<sup>219</sup> NIEIR, Electricity sales and customer numbers for the Powercor Australia region to 2019, June 2010 (Attachment 34 to this Revised Regulatory Proposal), pp100-1 (Tables 8.8 and 8.9).

<sup>220</sup> 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, Powercor Australia 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 Powercor Australia under its outsourcing arrangements. In particular, this Chapter responds to the AER's decision to exclude the margin payable by Powercor Australia 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, Powercor Australia accepts the following of the AER conclusions in the Draft Determination:

- the margin payable by Powercor Australia 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 Powercor Australia 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, Powercor Australia does not contest the AER's decision in the Draft Determination to exclude the administration fee payable by Powercor Australia 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.<sup>221</sup>

However, Powercor Australia 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.

Powercor Australia 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 Powercor Australia 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, Powercor Australia 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;

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<sup>221</sup> Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal.



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- 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, Powercor Australia maintains that the AER must accept its forecast 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 the implied margins, without adjustment because:

- the opex and capex 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 and capex objectives; and
- benchmarking analysis conducted by NERA and SKM establishes that Powercor Australia's forecast opex for 2011-15 set out in its Initial Regulatory Proposal and its unit rates for capital works employed in forecasting capex for 2011-15 in its Initial Regulatory Proposal and this Revised Regulatory Proposal, inclusive of any implied margins 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, are efficiently incurred.

In addition, Powercor Australia 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 Powercor Australia'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, Powercor Australia 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 Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal**

Within its Initial Regulatory Proposal, Powercor Australia 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<sup>222</sup> 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 Powercor Australia, 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 Powercor Australia; and
- DRMS – this Scheme was put in place in 2004. Under the terms of the Scheme, CHED Services provides in-fill insurance cover to Powercor Australia in respect of motor vehicle insurance and amounts below the policy deductibles for the following external insurance policies: liability insurance; and property insurance.

Powercor Australia considered these arrangements were efficient on the basis that:

- they complied with principles established by Powercor Australia's Board for the engagement of related parties;<sup>223</sup>
- the margins under the arrangements were paid in accordance with arm's length transfer prices determined by independent expert, Ernst & Young;<sup>224</sup> and

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<sup>222</sup> Initial Regulatory Proposal, p365.

<sup>223</sup> Initial Regulatory Proposal, p363.

- independent advice from KPMG indicated that had Powercor Australia 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 ■ per cent higher than the comparable actual direct costs incurred in that year.<sup>225</sup>

## **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 Powercor Australia's outsourcing arrangements.

### **5.4.1 Summary of AER's Findings**

Based on its assessment of each of Powercor Australia's outsourcing agreements, the AER concluded in its Draft Determination that the margins payable under the following arrangements entered into by Powercor Australia 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 Powercor Australia under these arrangements from the calculation of:

- forecast opex and capex for the 2011-15 regulatory control period,<sup>226</sup> and
- the EBSS carry over amounts for the 2011-15 regulatory control period.<sup>227</sup>

In addition, the AER excluded the margins payable by Powercor Australia under these arrangements from actual opex for 2006-09 in calculating the efficiency carry 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.<sup>228</sup>

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

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<sup>224</sup> Initial Regulatory Proposal, pp357-8.

<sup>225</sup> KPMG, The efficiencies of the Powercor Service Model, October 2009 (Attachment P0053 to the Initial Regulatory Proposal), p11.

<sup>226</sup> AER, Draft Determination, section 6.6.1, pp191-2; AER, Draft Determination Appendices, Appendix H, section H.2, pp25-33.

<sup>227</sup> AER, Draft Determination, section 6.5.8, p190.

<sup>228</sup> AER, Draft Determination, section 6.5.6, p188.

because it (correctly) conceded that this is required by clause 6.2.1(e)(1) of the Rules.<sup>229</sup>

The remainder of this section provides an overview of the AER's two stage assessment framework and the conclusions reached by the AER on Powercor Australia'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:<sup>230</sup>

- 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:<sup>231</sup>
  - 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 contract and the contract was not subject to an open tender process, then the contract is treated as having failed the 'presumption threshold'.

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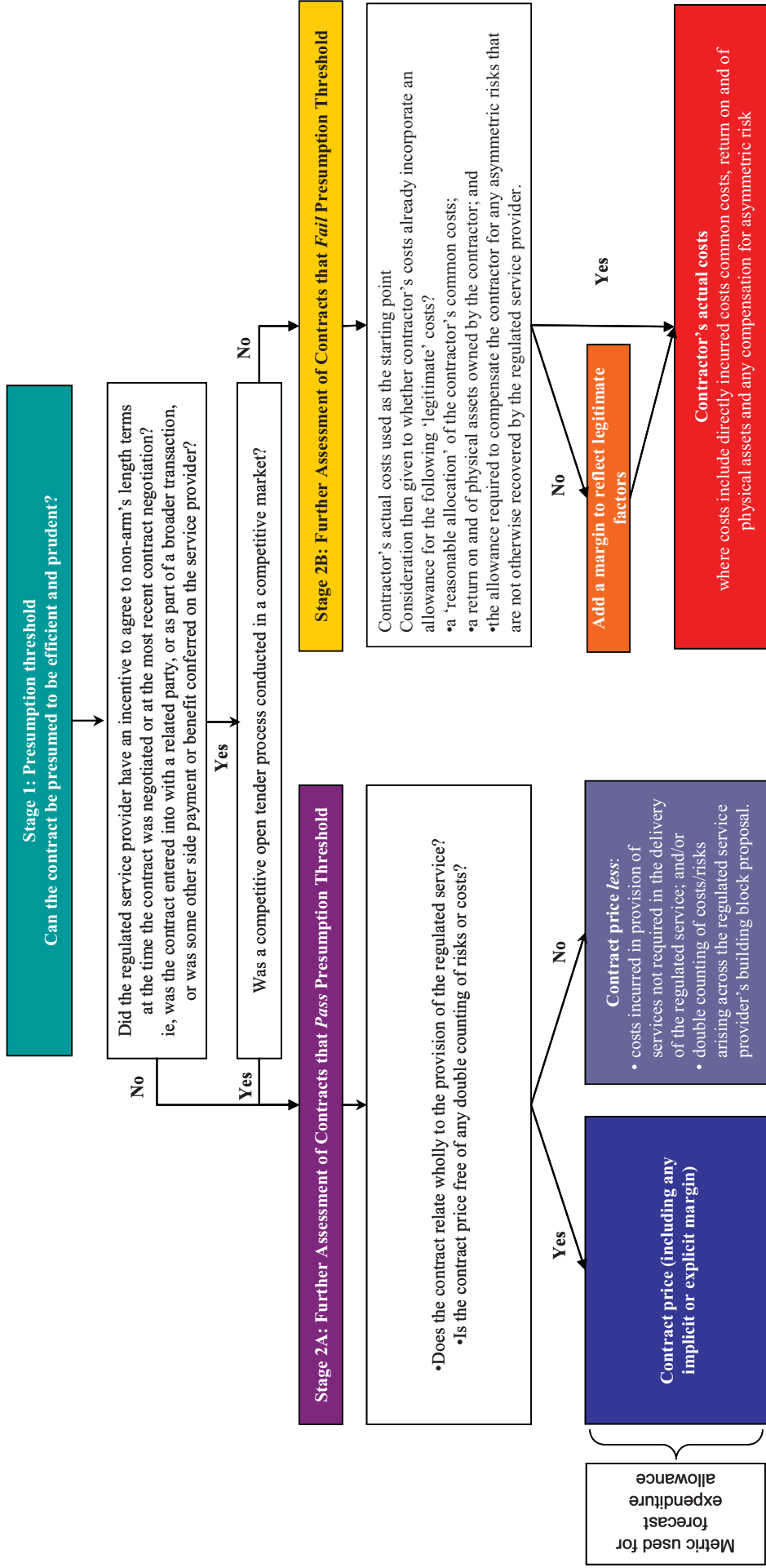
<sup>229</sup> AER, Draft Determination, section 6.5.7, pp188-90.

<sup>230</sup> AER, Draft Determination, p170.

<sup>231</sup> AER, Draft Determination, p170.



Figure 5.1: AER's Proposed Framework for Assessing Outsourcing Arrangements



Source: AER, Draft Determination, pp168-186.

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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.<sup>232</sup>

*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 prudence 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:<sup>233</sup>

- 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:

- First, the AER reasoned that:<sup>234</sup>
  - it is permitted by the Rules, in particular by the prudence criterion that is one of the three opex and capex criteria, to assess forecasts

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<sup>232</sup> AER, Draft Determination, p169.

<sup>233</sup> AER, Draft Determination, pp.180-2, 186.

<sup>234</sup> AER, Draft Determination, pp178-9.

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:<sup>235</sup>
  - 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:<sup>236</sup>

- 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
- 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

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<sup>235</sup> AER, Draft Determination, p182.

<sup>236</sup> AER, Draft Determination, pp182-3.

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that no margin would be incurred by a prudent operator in Powercor Australia's circumstances.<sup>237</sup>

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 Powercor Australia'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.<sup>238</sup> 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'*.<sup>239</sup>

#### **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 Powercor Australia'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.<sup>240</sup>

#### **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

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<sup>237</sup> AER, Draft Determination, Appendix H, pp26-7.

<sup>238</sup> Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment P0049 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 P0050 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services), 20 November 2006 (Attachment P0051 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 21 May 2009 (Attachment P0052 to the Initial Regulatory Proposal). As discussed in the Initial Regulatory Proposal (at p356), 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.

<sup>239</sup> AER, Draft Determination, pp187-8 and Appendix H at p26.

<sup>240</sup> 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 Maintenance Services, 30 November 2006 (Attachment P0048 to the Initial Regulatory Proposal). It was considered by the AER in its Draft Determination in Appendix H at p29.

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- the margin payable to CHED Services should be excluded from Powercor Australia's opex forecasts for the 2011-15 regulatory control period because a share of CHED Services' overheads was already included in Powercor Australia's base capex and opex forecasts and CHED Services did not appear to own any assets that were not already included in Powercor Australia's RAB.

In its assessment of this arrangement, the AER noted that the transfer of risk arising under this arrangement from Powercor Australia to CHED Services was not significant given the deductibles only relate to relatively low value amounts.<sup>241</sup> 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 Powercor Australia retained the risks.<sup>242</sup>

#### **5.4.6 Assessment of the Electrical Network Communications Agreement and Corporate Communications Agreement**

The AER's detailed assessment of Powercor Australia'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 Powercor Australia, 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 Powercor Australia 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.<sup>243</sup>

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.<sup>244</sup> 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'*.<sup>245</sup> The AER therefore excluded the margin payable under these arrangements from Powercor Australia's forecast opex and capex for the 2011-15 regulatory control period but left the door open to Powercor Australia to provide evidence to demonstrate that

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<sup>241</sup> AER, Draft Determination Appendices, Appendix H, p28.

<sup>242</sup> AER, Draft Determination Appendices, Appendix H, p28.

<sup>243</sup> AER, Draft Determination Appendices, Appendix H, p32.

<sup>244</sup> AER, Draft Determination Appendices, Appendix H, p33.

<sup>245</sup> AER, Draft Determination Appendices, Appendix H, p33.

some, or all, of the margin payable to Silk Telecom related to its recovery of common costs.

## **5.5 Powercor Australia's response to the AER's Draft Determination**

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

- the margin payable by Powercor Australia 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 Powercor Australia 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, Powercor Australia does not contest the AER's decision in the Draft Determination to exclude the administration fee payable by Powercor Australia 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.<sup>246</sup>

However, Powercor Australia 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.

Powercor Australia 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 Powercor Australia 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, Powercor Australia 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

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<sup>246</sup> Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal.



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- 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, Powercor Australia maintains that the AER must accept its forecast expenditure under the Corporate Services Agreement with CHED Services, the Network Services Agreement with PNS and the the Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom, including the implied margins, without adjustment because:

- the opex and capex 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 and capex objectives; and
- benchmarking analysis conducted by NERA and SKM establishes that Powercor Australia's forecast opex for 2011-15 set out in its Initial Regulatory Proposal and its unit rates for capital works employed in forecasting capex for 2011-15 in its Initial Regulatory Proposal and this Revised Regulatory Proposal, inclusive of any implied margins 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, are efficiently incurred.

In the remainder of this section 5.5, Powercor Australia responds, in turn, to:

- the AER's two stage assessment framework;
- the AER's assessment of Powercor Australia'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 Powercor Australia's Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom.

#### **5.5.1 Response to the AER's two stage assessment framework**

Powercor Australia 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 prudence criterion that is one of the three opex and capex criteria, to assess forecasts having

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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'*.

Powercor Australia 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
  - 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.

Powercor Australia 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**

Powercor Australia 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

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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 prudence 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 Powercor Australia under its various outsourcing arrangements should be excluded from its opex and capex forecasts for the 2011-15 regulatory control period. Accordingly, Powercor Australia sets out in Appendix 5.1 to this Revised Regulatory Proposal detailed legal analysis and conclusions on:

- the proper construction and application of the prudence criterion;
- the proper construction and application of the efficiency criterion; and
- the AER's discretion to balance the competing efficiency and prudence criteria.

Powercor Australia'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, Powercor Australia's views on the proper construction and application of the prudence 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 prudence 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 prudence criterion refers were intended to require a consideration of the network operating conditions of the DNSP and not its group structure.

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- 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 Powercor Australia 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*<sup>247</sup> 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;<sup>248</sup> and

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<sup>247</sup> [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].

<sup>248</sup> NEL, section 16; [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [14] & [74].

- 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*'.<sup>249</sup>

Powercor Australia 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 Powercor Australia 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**

Powercor Australia accepts 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 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, Powercor Australia 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. Powercor Australia 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

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<sup>249</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal), at [78].



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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<sup>250</sup> and the EBIT margin analysis contained in a report prepared by Impaq<sup>251</sup> 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, 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*<sup>252</sup>

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<sup>250</sup> 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).

<sup>251</sup> 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'Donnell 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.

<sup>252</sup> [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].



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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 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, Powercor Australia 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

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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 Powercor Australia'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.

Powercor Australia 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.<sup>253</sup> 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.<sup>254</sup> 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:<sup>255</sup>

- 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**;

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<sup>253</sup> AER, Draft Determination, pp162-8.

<sup>254</sup> ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p43.

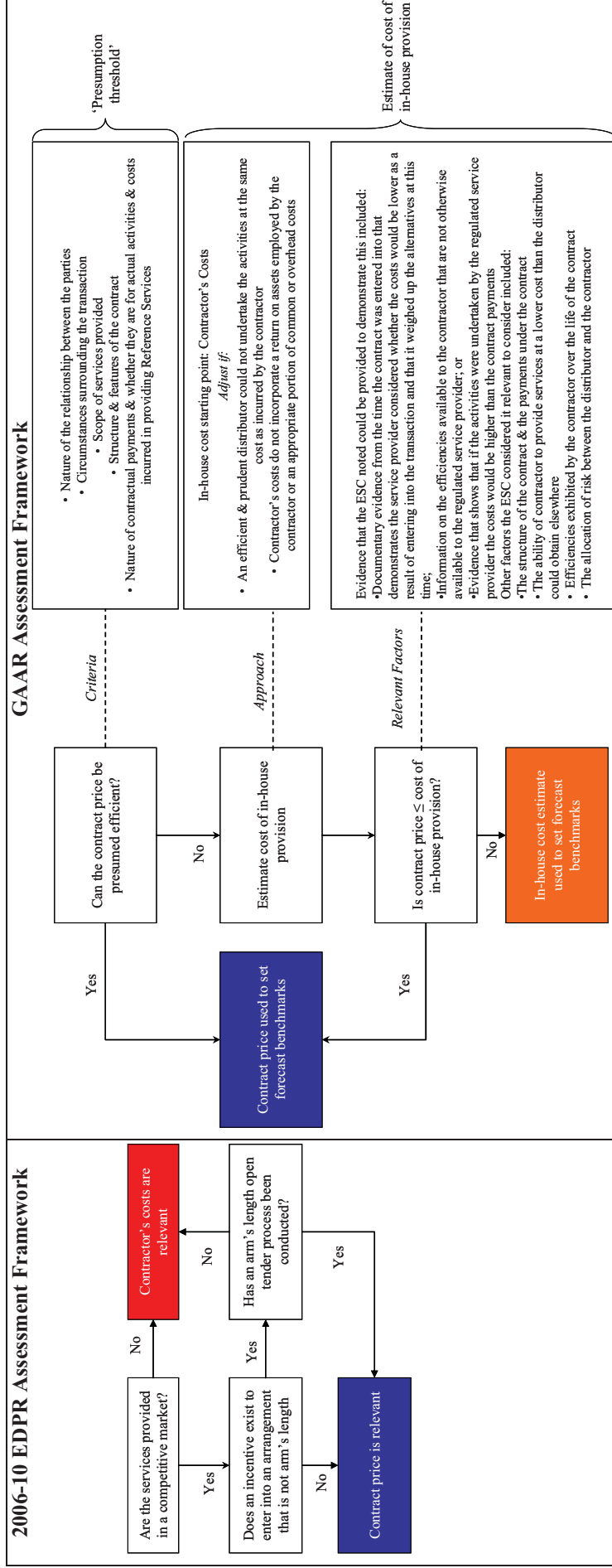
<sup>255</sup> ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), pp59-60.

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- 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
- the manner in which the contract 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.

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The position taken by the ESCV on this issue is reflected in the following statement:<sup>256</sup>

*'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:<sup>257</sup>

*'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, Powercor Australia 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.

#### **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

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<sup>256</sup> ESCV, Draft GAAR, Chapter 5 (Attachment 101 to this Revised Regulatory Proposal), p55.

<sup>257</sup> ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p52.

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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*'.<sup>258</sup> 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.<sup>259</sup> 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.<sup>260</sup> 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:<sup>261</sup>

*'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.

#### **5.5.1.5 Alternate assessment framework**

There are, in Powercor Australia'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.

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<sup>258</sup> AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p206.

<sup>259</sup> AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), pp. 56-7 and 273.

<sup>260</sup> AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), pp. 56-7 and 267-273.

<sup>261</sup> AER, Jemena Gas Access Final Decision (Attachment 104 to this Revised Regulatory Proposal), p270.



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To address these shortcomings, Powercor Australia 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,<sup>262</sup> Powercor Australia 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.

In other words the contract should move from Stage 2B of the AER's framework to Stage 2A of the framework.

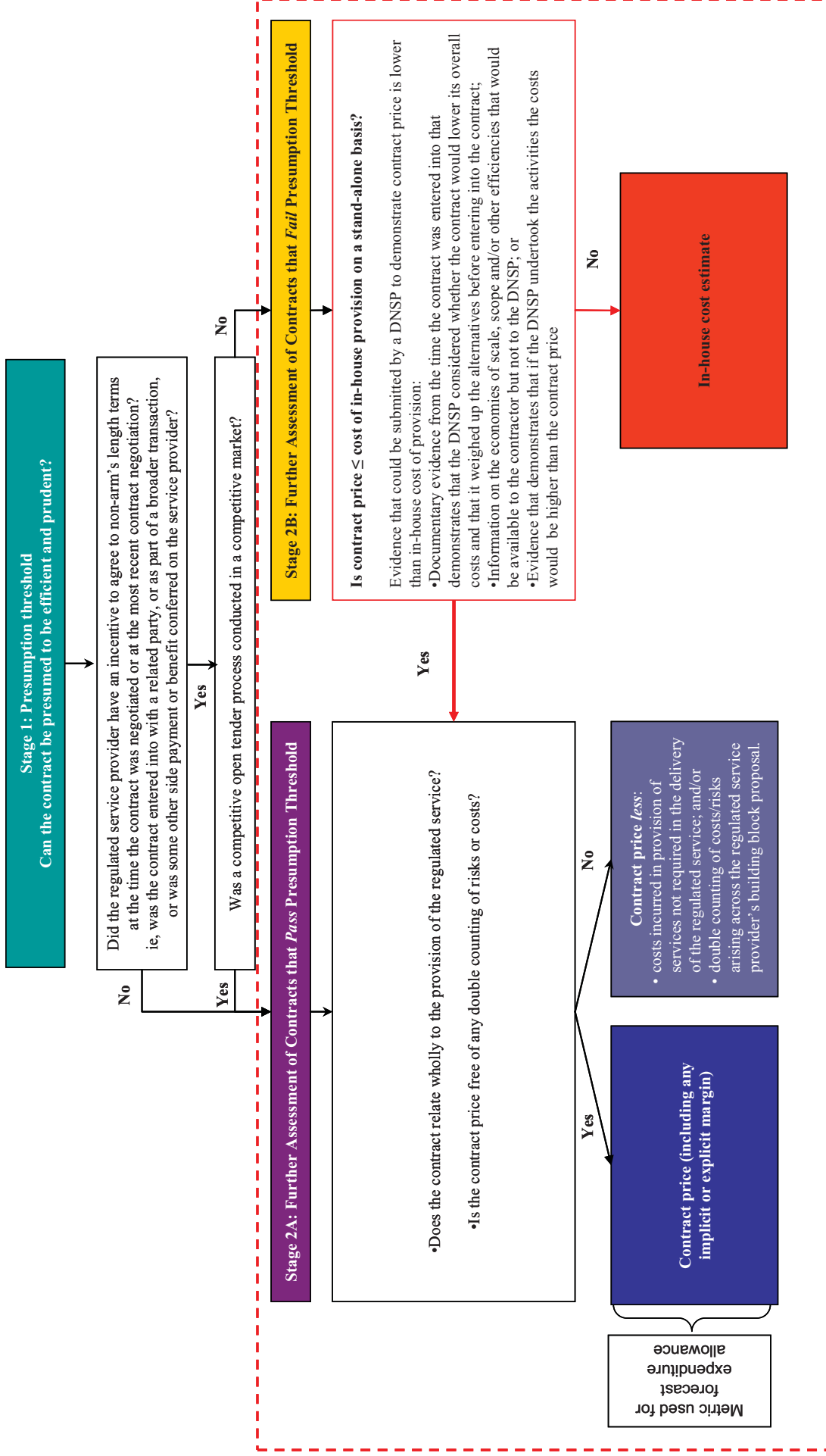
In those circumstances where a DNSP is unable to demonstrate that the contract price is lower than the in-house cost of provision, the AER should utilise the in-house cost estimate in the derivation of forecast opex and capex.

The modifications that Powercor Australia submits should be made to the AER's framework are set out in Figure 5.3 below.

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<sup>262</sup> ESCV, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p52.

Figure 5.3: Revised Framework for Assessing Outsourcing Arrangements



Other factors that Powercor Australia 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:<sup>263</sup>
  - 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.<sup>264</sup>

Powercor Australia 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 Powercor Australia 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**

Powercor Australia 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.

Powercor Australia 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 Powercor Australia'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.<sup>265</sup> The AER reasoned that:<sup>266</sup>

*'[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 (a cost it did not previously incur when providing the same*

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<sup>263</sup> ESC, Draft GAAR, Chapter 5 (Attachment 101 to this Revised Regulatory Proposal), p54.

<sup>264</sup> ESC, GAAR, Chapter 5 (Attachment 99 to this Revised Regulatory Proposal), p55.

<sup>265</sup> AER, Draft Determination, p192 and Appendix H at pp26 and 29.

<sup>266</sup> AER, Draft Determination, p192.

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*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.

Powercor Australia wishes to address this AER reasoning at the outset. Powercor Australia 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. Powercor Australia 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.<sup>267</sup> 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.<sup>268</sup>
- 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

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<sup>267</sup> Initial Regulatory Proposal, p365.

<sup>268</sup> 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).

previous service model. 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.<sup>269</sup>

- 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, Powercor Australia established that:

- the Rules permit the AER to substitute alternative expenditure forecasts only where Powercor Australia'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 Powercor Australia 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

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<sup>269</sup> 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*'.



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when assessing a DNSP's forecast expenditure under an outsourcing arrangement that fails the 'presumption threshold'.

On the basis of the foregoing, Powercor Australia 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:
  - Powercor Australia's forecast opex for 2011-15 set out in its Initial Regulatory Proposal inclusive of any expenditure incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS including implied margins; and
  - Powercor Australia's unit rates for capital works employed in forecasting capex for 2011-15 in its Initial Regulatory Proposal and this Revised Regulatory Proposal including any contract prices payable by Powercor Australia to CHED Services under the Corporate Services Agreement and PNS under the Network Services Agreement inclusive of implied margins,

are 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'.

Powercor Australia elaborates on each of these contentions in greater detail, in turn, below.

In addition, Powercor Australia 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<sup>270</sup> are of no relevance because differences in the objectives underpinning the tax and

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<sup>270</sup> Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment P0049 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 P0050 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services), 20 November 2006 (Attachment P0051 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 21 May 2009 (Attachment P0052 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 P0048 to the Initial Regulatory Proposal). As discussed in the Initial Regulatory Proposal (at p356), 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.



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*'<sup>271</sup>. Contrary to the AER's conclusion in the Draft Determination, Powercor Australia 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.

#### **5.5.2.1 Efficiency of expenditure forecasts inclusive of expenditure under Corporate Services Agreement and Network Services Agreement**

Powercor Australia 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:

- as discussed in section 5.5.1.1 above and Appendix 5.1 to this Revised Regulatory Proposal, the opex and capex 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 and capex objectives;
- in deciding whether it is satisfied that Powercor Australia's total expenditure forecasts reasonably reflect the opex and capex criteria, clauses 6.5.6(e)(4) and 6.5.7(e)(4) of the Rules provide that the AER must have regard to benchmark opex and capex that would be incurred by an efficient DNSP over the regulatory control period; and
- benchmarking analysis demonstrates that:
  - Powercor Australia's forecast opex for 2011-15 set out in its Initial Regulatory Proposal inclusive of any expenditure incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS including implied margins; and
  - Powercor Australia's unit rates for capital works employed in forecasting capex for 2011-15 in its Initial Regulatory Proposal and this Revised Regulatory Proposal including any contract prices payable by Powercor Australia to CHED Services under the Corporate Services Agreement and PNS under the Network Services Agreement inclusive of implied margins,

are 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

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<sup>271</sup> AER, Draft Determination, pp187-8 and Appendix H at pp26 and 29.

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the NEM<sup>272</sup> 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.<sup>273</sup>

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.<sup>274</sup>

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:

- using the top-down approach Powercor Australia was found to be the second most efficient DNSP of the 13 DNSPs examined by NERA;<sup>275</sup> and
- using the opex ratios previously employed by the AER, Powercor Australia ranked third in terms of opex per km, fifth in terms of opex per MW of maximum demand, sixth in terms of opex per customer and seventh in terms of opex per GWh of energy consumed and opex as a percentage of RAB.<sup>276</sup>

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:<sup>277</sup>

*'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*

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<sup>272</sup> The DNSPs included in this study include Energex, ETSA, Ergon, Jemena, UED, Country Energy, SP AusNet, Western Power, Integral Energy, Energy Australia and ActewAGL.

<sup>273</sup> 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.

<sup>274</sup> 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.

<sup>275</sup> NERA, Review of Operating Expenditure Efficiency, July 2010 (Attachment 102 to this Revised Regulatory Proposal), pp20-21.

<sup>276</sup> NERA, Review of Operating Expenditure Efficiency, July 2010 (Attachment 102 to this Revised Regulatory Proposal), Table C.1.

<sup>277</sup> AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), pp368-9.

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*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, Powercor Australia provides to the AER the results of a survey of market prices conducted by SKM as set out in a report entitled 'SKM Market Price Survey #4 – Results of a Survey for Powercor'. 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) and then compared this with the prices submitted by Powercor Australia. The results of the survey conducted by SKM are summarised in confidential Table 5.1.

The principal finding of the survey was that Powercor Australia's price was below the deemed market price across the eight categories surveyed. The results also indicated that in six of the categories surveyed, Powercor Australia's price was 15 per cent or more below the deemed market price and in one case was close to 40 per cent below the market price.<sup>278</sup>

Capex activity	Deemed market price	Powercor Australia's submitted price	Difference
Install 11kV / 22kV and LV underground cable in urban area	\$324,895	\$315,095	-3%
Install 11kV / 22kV underground cable in rural area	\$144,485	\$117,147	-18.9%
Construct 1km of 11kV / 22kV overhead line (wood pole, medium conductor) in urban area	\$73,749	\$56,633	-23.2%
Construct 1km of 11kV / 22kV overhead line (concrete pole, medium conductor) in urban area	\$95,742	\$90,574	-5.4%
Construct 1km of 11kV / 22kV overhead line (wood pole, medium conductor) in rural / regional area	\$42,195	\$26,015	-38.3%
Construct 1km of 11kV / 22kV overhead line (concrete pole, medium conductor) in rural / regional area	\$45,301	\$37,125	-18%
Construct 22kV / 415V or 11kV / 415V, 3 phase, 300kVA pole mounted substation (urban environment)	\$31,316	\$24,844	-20.7%
Install 500kVA, 3 phase, 11kV / 22kV – 415V kiosk or pad mounted substation	\$73,379	\$60,633	-17.4%

**Table 5.1 – Summary of SKM results for unit rate prices for capital works**

Powercor Australia's unit rates for capital works benchmarked by SKM were its 2009 unit rates and included any contract prices for capital works payable by Powercor Australia to CHED Services under the Corporate Services Agreement and PNS under the Network Services Agreement inclusive of implied margins. These same 2009 unit

<sup>278</sup> SKM, SKM Market Price Survey #4 – Results of Survey for Powercor, 6 July 2010 (Attachment 103 to this Revised Regulatory Proposal), piii.

rates were used by Powercor Australia as the unescalated unit rates in forecasting capex for the 2011-15 regulatory control period in its Initial Regulatory Proposal and this Revised Regulatory Proposal. Accordingly, it follows from the SKM results set out above that the unit rates employed by Powercor Australia in forecasting capex, including any contract prices payable by Powercor Australia to CHED Services under the Corporate Services Agreement and PNS under the Network Services Agreement inclusive of implied margins, are efficiently incurred.

### **5.5.2.2 Application of modified assessment framework to Corporate Services Agreement and Network Services Agreement**

Powercor Australia'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 Powercor Australia at the time they were entered into. While Powercor Australia 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, Powercor Australia does not agree that it is sufficient for the AER to simply presume that because Powercor Australia 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, Powercor Australia 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 Powercor Australia 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 Powercor Australia 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 Powercor Australia's forecast opex and unit rates for capital works employed in forecasting capex, inclusive of any implied margins incurred under the Corporate Services Agreement with CHED Services and the Network Services Agreement with PNS, are efficiently incurred.

*Overview of Corporate Services Agreement with CHED Services*

Under the terms of the Corporate Services Agreement, CHED Services provides Powercor Australia 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 Powercor Australia 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 Powercor Australia's forecast expenditure for 2011-15.

Prior to entering into the 2007 and 2008-10 Agreements, Powercor Australia's Board established strict governance arrangements for the engagement of related parties.<sup>279</sup> 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, Powercor Australia 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.<sup>280</sup>

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

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<sup>279</sup> Initial Regulatory Proposal, p363.

<sup>280</sup> KPMG, Powercor Australia Limited, Consideration of the arms length nature of the Shared Service Arrangements, December 2007 (Attachment P0092 to the Initial Regulatory Proposal), p1.



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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 Powercor Australia and CitiPower in 2006.<sup>281</sup> There are no other incentive payments or overheads payable by Powercor Australia under this Agreement.

*Overview of Network Services Agreement with PNS*

In 2008, Powercor Australia entered into the Network Services Agreement with PNS. Under the terms of this Agreement, PNS provides Powercor Australia 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 Powercor Australia Board in 2006 discussed above, Powercor Australia and PNS 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.<sup>282</sup>

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.<sup>283</sup> There was no incentive payment payable by Powercor Australia 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 Powercor Australia 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 Powercor Australia operating on a stand alone basis.<sup>284</sup> The nature of the services provided by

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<sup>281</sup> Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment P0049 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 P0050 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services), 20 November 2006 (Attachment P0051 to the Initial Regulatory Proposal); Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 21 May 2009 (Attachment P0052 to the Initial Regulatory Proposal). As discussed in the Initial Regulatory Proposal (at p356), 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.

<sup>282</sup> KPMG, Powercor Australia Limited, Consideration of the arms length nature of the Shared Service Arrangements, December 2007 (Attachment P0092 to the Initial Regulatory Proposal), p1.

<sup>283</sup> Ernst and Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services, 30 November 2006 (Attachment P0048 to the Initial Regulatory Proposal).

<sup>284</sup> 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



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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 Powercor Australia operating on a stand alone basis.

In view of the efficiencies available to both CHED Services and PNS, the service provision model adopted by Powercor Australia (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, Powercor Australia retained KPMG in 2009 to quantify both:

- the efficiencies arising from the service provision model; and
- the costs that would have been incurred by Powercor Australia 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 Powercor Australia on an in-house stand-alone basis.

KPMG's findings are set out in a report entitled, 'The efficiencies of the Powercor Services Model'.<sup>285</sup>

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 Powercor Australia 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:<sup>286</sup>

- CHED Services and PNS are in a better position to achieve lower costs and improved service performance than Powercor Australia 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 Powercor Australia; and
- If the services provided under the Corporate Services Agreement and Network Services Agreement had been provided by Powercor Australia on an in-house stand alone basis then its costs would have been \$16.93 million (approximately

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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).

<sup>285</sup> KPMG, The efficiencies of the Powercor Service Model, October 2009 (Attachment P0053 to the Initial Regulatory Proposal) and KPMG, Supplement to Report on Powercor Australia's service model, July 2010 (Attachment 105 to this Revised Regulatory Proposal).

<sup>286</sup> KPMG, The efficiencies of the Powercor Australia Service Model, October 2009 (Attachment P0053 to the Initial Regulatory Proposal), p3.

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21 per cent) higher in 2008 than the price actually paid under the contract in that year (\$96.212 million versus \$79.282 million).<sup>287</sup>

In Powercor Australia'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 Powercor Australia. Furthermore, it demonstrates that, while Powercor Australia 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.

Powercor Australia 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 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 Powercor Australia 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 Powercor Australia 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 Powercor Australia and set out:

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<sup>287</sup> KPMG, The efficiencies of the Powercor Australia Service Model, October 2009 (Attachment P0053 to the Initial Regulatory Proposal), p11.

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- 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 Powercor Australia 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 Powercor Australia 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 Powercor Australia'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 Powercor Australia 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 Powercor Australia 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.<sup>288</sup>

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 Powercor Australia'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 Powercor Australia 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.

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<sup>288</sup> KPMG, Powercor Australia Limited, Consideration of the arms length nature of the Shared Service Arrangements, December 2007 (Attachment P0092 to the Initial Regulatory Proposal), p1.

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 Powercor Australia 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 Powercor Australia, 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 Powercor Australia'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 Powercor Australia's expenditure forecast to be incurred under the Corporate Services Agreement and the Network Services Agreement, Powercor Australia 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 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 Powercor Australia'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, Powercor Australia has reviewed PNS' 2009 Regulatory Accounts and CitiPower and Powercor Australia's 2009 Regulatory Accounts<sup>289</sup> to determine what proportion of its revenue was derived from parties other than CitiPower and Powercor Australia.

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<sup>289</sup> 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 Cleve, 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).

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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.<sup>290</sup> 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 Powercor Australia under the Network Services Agreement was not artificially inflated.

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<sup>290</sup> 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.



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	Powercor Australia	CitiPower	Other	Total
Costs	■	■	■	■
Revenue	■	■	■	■
Margin	■	■	■	■
% of Total revenue generated by PNS	■	■	■	

**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);
- 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

<sup>291</sup> 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.

<sup>292</sup> 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.

<sup>293</sup> 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).

<sup>294</sup> 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.

<sup>295</sup> 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'.

<sup>296</sup> 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'.

<sup>297</sup> 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).

<sup>298</sup> 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 commenced a project valued at \$3million to design and construct the Country Energy Buronga Zone Substation in NSW.

The benefits to Powercor Australia 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 Powercor Australia;
- increased buying power in the logistics/supply chain, so reducing costs to Powercor Australia for equipment, materials and contracts sourced for them;
- reduced overhead costs for Powercor Australia 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 Powercor Australia.

#### **5.5.2.4 Margins under Corporate Services Agreement and Network Services Agreement reflect arm's length margins**

Powercor Australia 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, Powercor Australia 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'*.<sup>299</sup> Powercor Australia 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.<sup>300</sup>

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

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<sup>299</sup> AER, Draft Determination, pp187-8.

<sup>300</sup> Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment P0049 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 P0048 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 P0050 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 P0051 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 P0052 to the Initial Regulatory Proposal), p4.

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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.<sup>301</sup> The application of the ATO's ruling requires consideration to be given to:<sup>302</sup>

- 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.

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<sup>301</sup> Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment P0049 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 P0048 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 P0050 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 P0051 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 P0052 to the Initial Regulatory Proposal), p6.

<sup>302</sup> Ernst & Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006 (Attachment P0049 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 P0048 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 P0050 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 P0051 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 P0052 to the Initial Regulatory Proposal), pp 5-7.

Powercor Australia 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 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 Powercor Australia'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 Powercor Australia'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 Powercor Australia 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, Powercor Australia 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, Powercor Australia'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 Powercor Australia in 2011-15.

As set out in Powercor Australia's Initial Regulatory Proposal, Powercor Australia commissioned Aon to calculate the self-insurance premiums that Powercor Australia could expect to pay into the DRMS in each year in the 2011-15 regulatory control period.<sup>303</sup> The self-insurance premiums for 2011-15 calculated by Aon in its report 'Powercor Australia Self Insurance Risk Quantification'<sup>304</sup> are set out in Table 6-18 in the Initial Regulatory Proposal.<sup>305</sup> As disclosed by section 2.2 of the Aon report, which discusses Aon's methodology and approach to determining Powercor Australia'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 Powercor Australia's forecast opex on self-insurance for 2011-15 set out in the Initial Regulatory Proposal, it follows that Powercor Australia'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.<sup>306</sup>

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<sup>303</sup> Initial Regulatory Proposal, pp180-1.

<sup>304</sup> Attachment P0066 to the Initial Regulatory Proposal.

<sup>305</sup> Initial Regulatory Proposal, p181.

<sup>306</sup> Powercor Australia'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 Powercor Australia'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 Powercor Australia'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 Powercor Australia's actual opex in the

#### **5.5.4 Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom**

Powercor Australia disagrees with the AER's assessment of the margins payable to Silk Telecom under the Electrical Network Communications Agreement and the Corporate Communications Agreement.

Powercor Australia 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.

Powercor Australia maintains that the AER must accept its forecast expenditure 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 and capex 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 and capex objectives;
- in deciding whether it is satisfied that Powercor Australia's total expenditure forecasts reasonably reflect the opex and capex criteria, clauses 6.5.6(e)(4) and 6.5.7(e)(4) of the Rules provide that the AER must have regard to benchmark opex and capex that would be incurred by an efficient DNSP over the regulatory control period; and
- benchmarking analysis demonstrates that:
  - Powercor Australia's forecast opex for 2011-15 set out in its Initial Regulatory Proposal inclusive of any expenditure incurred under the Electrical Network Communications Agreement and the Corporate Communications Agreement with Silk Telecom including implied margins is efficient; and
  - Powercor Australia's unit rates for capital works employed in forecasting capex for 2011-15 in its Initial Regulatory Proposal and this Revised Regulatory Proposal including any contract prices payable by Powercor Australia to Silk Telecom under the Electrical Network Communications Agreement and the Corporate Communications Agreement inclusive of implied margins are efficiently incurred.

Section 5.5.2.1 above discusses the relevant benchmarking analysis.

In addition, Powercor Australia observes that:

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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.

- 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:<sup>307</sup>
  - 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 Powercor Australia 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'*.<sup>308</sup>
- 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 Powercor Australia 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, Powercor Australia has not been able to obtain from Silk Telecom the information required by Powercor Australia 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

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<sup>307</sup> AER, Draft Determination Appendices, Appendix H, p33.

<sup>308</sup> AER, Draft Determination Appendices, Appendix H, p33.



- any scale, scope or other efficiencies accruing by reason of Silk Telecom's provision of services to parties outside the group to which Powercor Australia belongs.

Powecor Australia 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, Powercor Australia observes that:

- when Silk Telecom was part of the group to which Powercor Australia 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, Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia'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, Powercor Australia 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, Powercor Australia also observes that, for the purposes of this Revised Regulatory Proposal and for the reasons cited by the AER in its Draft Determination, Powercor Australia 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, Powercor Australia responds to:

- Chapter 7 of the Draft Determination in respect of opex; and
- Appendix L of the Draft Determination in respect of step changes.

Powercor Australia also sets out its revised opex forecast for the 2010-15 regulatory control period. Powercor Australia 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 Powercor Australia 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 Powercor Australia'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, Powercor Australia has proposed in this Revised Regulatory Proposal correct adjustments to account for movement in provisions relating to employee entitlements and in respect of capitalisation. Powercor Australia 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.

Powercor Australia 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**

Powercor Australia 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**

Powercor Australia does not accept the AER's decision in respect of its proposed step change for compliance with the 2010 Line Clearance Regulations. Powercor Australia 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.

Powercor Australia does not accept the AER's decision to reject its proposed step change in respect of its at risk townships program. Powercor Australia believes in light of community expectations, a prudent operator would undertake works such as its program. The AER has not cited, and Powercor Australia is not aware, of any legislative reason why the AER has to wait until the Victorian Government implements its response to the Bushfires Royal Commission. It is imprudent of the AER not to

consider the program at this time given that the opportunity to mitigate some of the fire risks posed by distribution assets around at risk townships exists today.

In respect of its insurance step change, Powercor Australia proposes to provide the AER with invoices for its actual premiums once they become available in September 2010. Powercor Australia will accept a step change that reflects the difference between its 2009 and 2010 external insurance.

The AER failed to comment on Powercor Australia'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 Powercor Australia which are not reflected in its base year opex. It is necessary for the AER to allow this step change for Powercor Australia 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, Powercor Australia 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.

Powercor Australia 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, Powercor Australia considers that there may be a range of forecasts that reasonably reflect the opex criteria.<sup>309</sup> Powercor Australia appreciates that the AER may need to assess the methodology, approaches and input values used to develop the total forecast.

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<sup>309</sup> 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.

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 Powercor Australia'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 opex criteria. The AER is not permitted to reject a total forecast put forward by Powercor Australia 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 Powercor Australia 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 Powercor Australia'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.<sup>310</sup>

### **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

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<sup>310</sup> 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.

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 Powercor Australia's Initial Regulatory Proposal**

In Chapter 6 of its Initial Regulatory Proposal, Powercor Australia:

- proposed total forecast opex for the 2011-15 regulatory control period of \$902,222,000 (\$2010);
- 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.<sup>311</sup> Since Powercor Australia'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<sup>312</sup>:

- 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

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<sup>311</sup> AER, Draft Determination, p238.

<sup>312</sup> AER, Draft Determination, pp240-6.

- 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.<sup>313</sup>

The AER rejected Powercor Australia'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.<sup>314</sup>

The AER rejected Powercor Australia's proposed step changes for:

- self insurance;
- insurance;
- climate change;
- compliance with the Electricity Safety Management Regulations;
- compliance with the 2010 Line Clearance Regulations; and
- its at risk townships project.

The AER failed to comment on Powercor Australia's proposed step change for communications in extreme supply events.

The AER accepted Powercor Australia's proposed step changes for the national framework for distribution network planning and expansion. The AER also accepted a step change for Powercor Australia in respect of the customer charter (although it reduced the amount of the step change proposed by Powercor Australia). The AER also gave Powercor Australia a step change in respect of regulatory submission costs.

## **6.5 Powercor Australia's response to AER's Draft Determination**

Powercor Australia has reviewed all of the matters raised by the AER in its Draft Determination, including where the AER has made adjustments to Powercor Australia's Initial Regulatory Proposal.

Powercor Australia 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;<sup>315</sup>
- 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;<sup>316</sup>

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<sup>313</sup> AER, Draft Determination, p246.

<sup>314</sup> AER, Draft Determination, pp249-61.

<sup>315</sup> AER, Draft Determination, p243.

<sup>316</sup> AER, Draft Determination, p246.

- the AER's decision in respect of Powercor Australia's proposed step change for self insurance;<sup>317</sup>
- the AER's decision in respect of Powercor Australia's proposed step change for climate change;<sup>318</sup>
- the AER's decision in respect of Powercor Australia's proposed step change for compliance with the Electricity Safety Management Regulations;<sup>319</sup>
- the AER's decision in respect of Powercor Australia's proposed step change for the national framework for distribution network planning and expansion;<sup>320</sup>
- the AER's decision in respect of Powercor Australia's proposed step change in respect of the customer charter;<sup>321</sup> and
- the AER's decision to include a step change for Powercor Australia in respect of regulatory submission costs.<sup>322</sup>

Powercor Australia 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;<sup>323</sup>
- the AER's adjustment to base year opex in respect of Powercor Australia's distribution licence fee;<sup>324</sup>
- the AER's adjustment to base year costs in respect of GSL payments;<sup>325</sup>
- the AER's adjustment in respect of capitalisation;<sup>326</sup>
- the AER's adjustment to base year costs in respect of superannuation payments;<sup>327</sup>
- the AER's decision to reject Powercor Australia's proposed step change in respect of insurance;<sup>328</sup>
- the AER's decision in respect of Powercor Australia's proposed step change in respect of compliance with the 2010 Line Clearance Regulations;<sup>329</sup>
- the AER's decision in respect of Powercor Australia's proposed step change in respect of its at risk townships project;<sup>330</sup>

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<sup>317</sup> AER, Draft Determination, Appendix M.

<sup>318</sup> AER, Draft Determination, Appendix L, p186.

<sup>319</sup> AER, Draft Determination, Appendix L, p159.

<sup>320</sup> AER, Draft Determination, Appendix L, p197.

<sup>321</sup> AER, Draft Determination, Appendix L, p203.

<sup>322</sup> AER, Draft Determination, Appendix L, p208.

<sup>323</sup> AER, Draft Determination, p242.

<sup>324</sup> AER, Draft Determination, p242.

<sup>325</sup> AER, Draft Determination, p242.

<sup>326</sup> AER, Draft Determination, p246.

<sup>327</sup> AER, Draft Determination, p244.

<sup>328</sup> AER, Draft Determination, pp191-2.

<sup>329</sup> AER, Draft Determination, Appendix L, p171.

<sup>330</sup> AER, Draft Determination, Appendix L, p232.



- the AER's failure to comment on Powercor Australia's proposed step change for communications in extreme supply events;
- the AER's decision in respect of Powercor Australia's debt raising costs;
- the AER's decision in respect of scale escalation (Powercor Australia responds to this in Chapter 7 of this Revised Regulatory Proposal); and
- the AER's decision in respect of real cost escalation (Powercor Australia responds to this in Chapter 8 of its Revised Regulatory Proposal).

In addition, Powercor Australia 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).

Powercor Australia notes that:

- The AER asked Victorian DNSPs to provide forecast expenditure associated with any avoided DuOS.<sup>331</sup> Powercor Australia 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 Powercor Australia's audited 2009 accounts for its final decision and, where necessary, make an adjustment to remove any AMI related adjustments.<sup>332</sup> Powercor Australia observes that it does not have any AMI related adjustments in its audited 2009 accounts.

The aspects of the AER's Draft Determination which Powercor Australia disputes are expanded upon below.

### **6.5.1 Base year expenditure**

Powercor Australia 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. Powercor Australia 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.<sup>333</sup>

### **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. Powercor Australia does not disagree in

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<sup>331</sup> AER, Draft Determination, p242.

<sup>332</sup> AER, Draft Determination, p242.

<sup>333</sup> AER, Draft Determination, p238.

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principle with making such adjustments. However the AER has 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 2009 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 unaudited 2009 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.

	2009
	Labour Costs
Operating Expenditure	████
Maintenance Expenditure	████
Capital Expenditure	████
Total	████

**Table 6.1 Labour cost split for 2009**

The second and third issues were highlighted in Powercor Australia's letter to the AER of 3 February 2010 regarding 'Regulatory Accounts, Provisions and AMI Adjustment to Regulatory Accounts'.<sup>334</sup>

Powercor Australia engaged its external auditor, Deloitte to review all the movements in provisions proposed by Powercor Australia. Deloitte has confirmed the adjustments proposed by Powercor Australia to be correct.<sup>335</sup>

### **6.5.3 Exclusion of related party margins**

Powercor Australia does not accept the AER's decision to exclude related party margins from base year opex in forecasting opex for 2011-15. Powercor Australia

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<sup>334</sup> Attachment 217 to this Revised Regulatory Proposal

<sup>335</sup> Letter from T Imbesi, Partner, Deloitte, to J Williams, Chief Financial Officer, CHEDA, titled 'Powercor Regulatory Accounts: Accounting treatment of provisions', 20 July 2010 (Attachment 218 to this Revised Regulatory Proposal).

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.<sup>336</sup>

The AER deducted approximately \$0.8 million for Powercor Australia's distribution licence fees.

##### **6.5.4.2 Powercor Australia's response to the AER's Draft Determination**

The adjustment which the AER made for Powercor Australia's distribution licence fees is too high. Powercor Australia's actual distribution licence fees for 2009 were \$302,995. Accordingly, the AER should adjust that amount from Powercor Australia'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 Powercor Australia's 2009 distribution licence fees.<sup>337</sup>

#### **6.5.5 Guaranteed service level payments**

##### **6.5.5.1 Powercor Australia's Initial Regulatory Proposal**

Powercor Australia 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 Powercor Australia'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.<sup>338</sup> It provided Powercor Australia 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 Powercor Australia's forecast of GSL payments based upon 2009 because it considered that GSL payments in that year appeared abnormally high.<sup>339</sup> Further, the AER did not accept the customer growth factor which Powercor Australia applied to its forecasts.

##### **6.5.5.3 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia 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, Powercor Australia 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

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<sup>336</sup> AER, Draft Determination, p242.

<sup>337</sup> Attachment 129 to this Revised Regulatory Proposal.

<sup>338</sup> AER, Draft Determination, p242.

<sup>339</sup> AER, Draft Determination, p687.

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increase. Accordingly, Powercor Australia has applied the customer growth factor set out in Chapter 7 of this Revised Regulatory Proposal to its average GSL payment value.

Powercor Australia 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.<sup>340</sup>

Powercor Australia's forecast GSL payments are set out in the following table.

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>GSL payments</b>	1,152	1,152	1,152	1,152	1,152	<b>5,761</b>

Table 6.2 Forecast GSL payments

## **6.5.6 Capitalisation adjustment**

### **6.5.6.1 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia determined the allocation of overheads in accordance with its overhead allocation policy based on its proposed capex and opex costs and service classification.<sup>341</sup> Powercor Australia 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. Powercor Australia's other proposed step changes were presented 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 Powercor Australia's adjustment for the reassignment of overhead costs due to increases in capital costs, referring to it as a '*capitalisation adjustment*'.<sup>342</sup> The AER reduced Powercor Australia's base level of opex by \$4 million (\$2010). The AER correspondingly increased Powercor Australia's capex associated with indirect overheads.

### **6.5.6.3 Powercor Australia's Response to AER's Draft Determination**

#### *Powercor Australia'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 Powercor Australia's accounting policy.

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<sup>340</sup> Attachment 12 to this Revised Regulatory Proposal.

<sup>341</sup> Initial Regulatory Proposal, p144.

<sup>342</sup> AER, Draft Determination, p246.

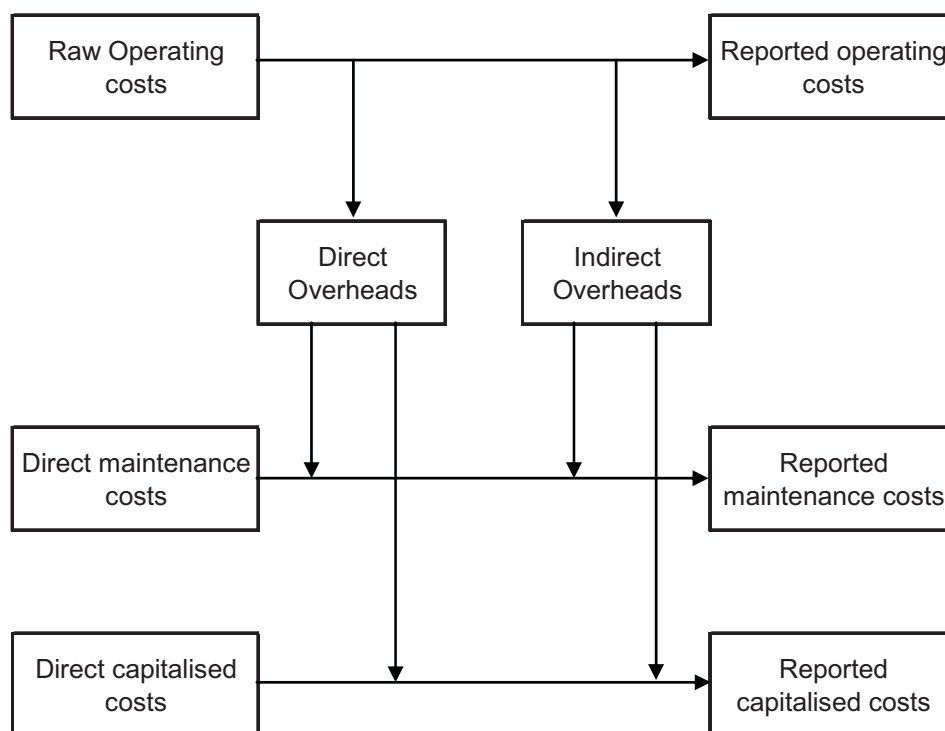


Figure 6.1 Flow of overheads between operating, maintenance and capital costs

Powercor Australia 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:

- 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 Powercor Australia'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 Powercor Australia;
- 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 Powercor Australia for related party margins. The adjustment in Powercor Australia's Initial Regulatory Proposal included related party margins. This is because Powercor Australia'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 Powercor Australia's proposed adjustment for margins; and
- the AER did not re-allocate the overheads associated with Powercor Australia'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 \$21.7 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 Powercor Australia has proposed in this Revised Regulatory Proposal, it should ask Powercor Australia 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 Powercor Australia's overhead allocation policy, the AER will be in error, inconsistent with Powercor Australia'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 Powercor Australia 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.



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Overheads are calculated in the Cost Forecast Model provided as an attachment to this Revised Regulatory Proposal.<sup>343</sup>

	\$'000 (\$2010)						
	2009	2010	2011	2012	2013	2014	2015
<b>DIRECT OVERHEADS</b>							
<b>Overhead pool</b>							
Standard Control capex	5,485	5,576	5,997	5,957	5,901	5,808	5,788
Standard Control O&M	1,777	1,641	1,346	1,365	1,404	1,479	1,512
Other Services	1,147	1,191	1,066	1,087	1,104	1,122	1,109
<b>Total</b>	<b>8,409</b>	<b>8,409</b>	<b>8,409</b>	<b>8,409</b>	<b>8,409</b>	<b>8,409</b>	<b>8,409</b>
<b>Step change</b>							
Standard Control capex	0	91	511	472	416	322	302
Standard Control O&M	0	(135)	(431)	(412)	(373)	(297)	(265)
Other Services	0	45	(81)	(60)	(43)	(25)	(38)
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>INDIRECT OVERHEADS</b>							
<b>Overhead pool</b>							
Standard Control capex	19,282	19,558	20,047	20,102	20,242	20,016	19,961
Standard Control O&M	12,094	11,876	11,611	11,463	11,230	11,407	11,475
Other Services	2,653	2,595	2,371	2,463	2,557	2,606	2,593
<b>Total</b>	<b>34,029</b>	<b>34,029</b>	<b>34,029</b>	<b>34,029</b>	<b>34,029</b>	<b>34,029</b>	<b>34,029</b>
<b>Step change</b>							
Standard Control capex	0	276	766	820	960	734	679
Standard Control O&M	0	(219)	(484)	(631)	(865)	(687)	(619)
Other Services	0	(58)	(282)	(189)	(96)	(47)	(60)
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>TOTAL OVERHEADS</b>							
<b>Overhead pool</b>							
Standard Control capex	24,767	25,134	26,044	26,059	26,143	25,824	25,749
Standard Control O&M	13,871	13,517	12,957	12,828	12,634	12,886	12,987
Other Services	3,799	3,786	3,437	3,550	3,661	3,727	3,702
<b>Total</b>	<b>42,437</b>	<b>42,437</b>	<b>42,437</b>	<b>42,437</b>	<b>42,437</b>	<b>42,437</b>	<b>42,437</b>
<b>Step change</b>							
Standard Control capex	0	367	1,277	1,292	1,376	1,056	982
Standard Control O&M	0	(354)	(914)	(1,043)	(1,237)	(985)	(884)
Other Services	0	(13)	(362)	(249)	(139)	(72)	(97)
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>

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 Powercor Australia's Initial Regulatory Proposal

In Chapter 6 of its Initial Regulatory Proposal, Powercor Australia included debt raising costs as an element of its opex forecasts. Powercor Australia 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.<sup>344</sup>

<sup>343</sup> Attachment 10 to this Revised Regulatory Proposal.

### 6.5.7.2 AER's Draft Determination

The AER did not accept Powercor Australia'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;<sup>345</sup>
- early debt refinancing costs were a legitimate expense for which DNSPs should be compensated;<sup>346</sup>
- the AER's estimate of the amount of early debt refinancing costs was 4-8 basis points per annum, based on the underwriting method;<sup>347</sup>
- 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.<sup>348</sup>

### 6.5.7.3 Powercor Australia's Response to AER's Draft Determination

Powercor Australia does not accept the AER's position in relation to debt raising costs.

Powercor Australia 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.

Powercor Australia does not agree that early refinancing costs are included in the calculation of direct debt raising costs.

Powercor Australia's forecast debt raising costs are set out in the following table.

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Debt raising costs</b>	3,187	3,475	3,764	4,043	4,321	<b>18,791</b>

Table 6.4: Debt raising costs

## 6.5.8 Step change - Superannuation payments

### 6.5.8.1 Powercor Australia's Initial Regulatory Proposal

In its Initial Regulatory Proposal, Powercor Australia 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.<sup>349</sup> 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 in the required contribution rates, particularly in

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<sup>344</sup> Powercor Australia's Initial Regulatory Proposal p188-90.

<sup>345</sup> AER, Draft Determination, Appendix P, p337.

<sup>346</sup> AER, Draft Determination, Appendix P, p345.

<sup>347</sup> AER, Draft Determination, Appendix P, p343.

<sup>348</sup> AER, Draft Determination, Appendix P, p345.

<sup>349</sup> Initial Regulatory Proposal, p226.

2009. Powercor Australia stated that the volatility in defined superannuation contributions has resulted in a variation between Powercor Australia'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.<sup>350</sup> 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 Powercor Australia's actuarial adjustment to defined benefit scheme contributions to be \$5 million (\$2010) and removed this amount from Powercor Australia's base year opex. The AER said that this adjustment was based on the difference between Powercor Australia's estimated cost of \$10 million (\$2010) in 2009 and its average costs over 2006-08. The AER said it would require Powercor Australia 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.<sup>351</sup> 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 Powercor Australia's response to AER's Draft Determination**

In response to the AER's Draft Determination, Powercor Australia 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 \$5 million to Powercor Australia's base year opex is incorrect. Firstly, the adjustment is based on all superannuation contributions rather

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<sup>350</sup> AER, Draft Determination, p244.

<sup>351</sup> AER, Draft Determination, p555.

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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.

Powercor Australia 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.<sup>352</sup> Mercer's Report is attached to this Revised Regulatory Proposal.<sup>353</sup> In addition, Powercor Australia has provided the cost build up model for this step change as an attachment to this Revised Regulatory Proposal.<sup>354</sup>

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. Powercor Australia 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.<sup>355</sup> Powercor Australia 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.

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<sup>352</sup> 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).

<sup>353</sup> 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).

<sup>354</sup> Attachment 13 to this Revised Regulatory Proposal.

<sup>355</sup> 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.

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	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Mercer Report forecast defined benefit fund contributions</b>	-760	-1,381	-1,972	-2,536	-3,081	<b>-9,730</b>
<b>Incremental increase in accumulation fund contributions to replace employees who have departed the defined benefit fund</b>	838	1,687	2,592	3,546	4,628	<b>13,292</b>
<b>Total step change</b>	<b>77</b>	<b>306</b>	<b>620</b>	<b>1,010</b>	<b>1,547</b>	<b>3,561</b>

**Table 6.5 Step change - defined benefit fund and accumulation fund contributions**

*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.<sup>356</sup> 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 Powercor Australia.

Powercor Australia has calculated that the proposed changes to the superannuation guarantee levy would result in a step change of over 2013-15 in accumulation payments, prior to escalation. Powercor Australia has provided the cost build up model for this step change as an attachment to this Revised Regulatory Proposal.<sup>357</sup>

Powercor Australia 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.

<sup>356</sup> 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).

<sup>357</sup> Attachment 13 to this Revised Regulatory Proposal.

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	\$'000 (\$2010)			
	2013	2014	2015	Total
Superannuation guarantee levy	121	379	790	1,289

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 Powercor Australia's Initial Regulatory Proposal

In Chapter 6 of its Initial Regulatory Proposal, Powercor Australia proposed a step change of \$27.5 million for opex resulting from insurance premiums above those reflected in Powercor Australia's 2009 base year opex.<sup>358</sup>

Powercor Australia 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 Powercor Australia's insurance premiums were likely to increase considerably in the next regulatory control period.<sup>359</sup>

Powercor Australia 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. Powercor Australia 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 Powercor Australia can prudently manage the costs of unforeseen 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 Powercor Australia'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 Powercor Australia's insurance premiums.<sup>360</sup> It considered that Aon had not explained why it chose these particular drivers or demonstrated that Powercor Australia'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.

<sup>358</sup> Initial Regulatory Proposal p167-8.

<sup>359</sup> Aon Risk Services Australia, Powercor Australia Ltd Insurance Cost Projections, October 2009 (Attachment P0067 to the Initial Regulatory Proposal).

<sup>360</sup> AER, Draft Determination, Appendix L, p189.



The AER considered that Aon had not demonstrated that Powercor Australia'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.<sup>361</sup>

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.<sup>362</sup> The AER said that while it had not accepted Powercor Australia's liability insurance forecasts, it expected that most of the re-pricing of insurance premiums as a result of bushfires in 2009 was likely to be reflected in the 2010 premiums. Accordingly, it said that if Powercor Australia submitted its 2010 bushfire liability premiums with its revised proposal, the AER may be satisfied that the difference between its 2009 and 2010 premiums reflect a realistic expectation of cost inputs over the forthcoming regulatory control period.

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 Powercor Australia's Response to AER's Draft Determination**

Powercor Australia observes that its insurance program is undertaken jointly with CitiPower and ETSA. The AER decided that ETSA forecast network insurance opex reasonably reflected the opex criteria. Similar to Powercor Australia and CitiPower, ETSA commissioned Aon to provide an estimate of its insurance costs for the next regulatory control period. PB reviewed Aon's report at the AER's request. The AER observes in its South Australian Draft Determination that:<sup>363</sup>

*'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:<sup>364</sup>

*'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.'*<sup>365</sup>

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<sup>361</sup> AER, Draft Determination, Appendix L, p190.

<sup>362</sup> AER, Draft Determination, Appendix L, p191-2.

<sup>363</sup> AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p220.

<sup>364</sup> AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p221

<sup>365</sup> AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p221.

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 Powercor Australia, the AER accepted the asset value growth and revenue growth as 'business trend' drivers chosen by Aon in its report for ETSA .

Similar to Powercor Australia, 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.<sup>366</sup> 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 Powercor Australia'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'.<sup>367</sup> It is inconsistent for the AER to reject Powercor Australia'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 Powercor Australia 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 Powercor Australia's proposed step change for insurance in circumstances where Powercor Australia 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 Powercor Australia's insurance renewal amount for 2010 in order to accept an insurance step change for Powercor Australia.

Powercor Australia's process for renewing its insurance is currently taking place. Powercor Australia will not have its actual insurance premiums until September 2010. Accordingly, Powercor Australia is not currently in a position to provide the AER with invoices showing its actual insurance premiums. Powercor Australia proposes to provide the AER with those invoices as soon as it is able to, which will likely be on 30 September 2010. Powercor Australia's process for insurance renewal is thorough and, accordingly, lengthy. Powercor Australia 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 Powercor Australia, CitiPower 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.

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<sup>366</sup> AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p220.

<sup>367</sup> AER, Draft Determination, Appendix L, p189.

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Month	Activity
<b>October</b>	<ul style="list-style-type: none"> <li>• Renew the insurance liability submission (copy provided to the insurance underwriters) to identify any improvements in the Businesses' internal processes.</li> </ul>
<b>December</b>	<ul style="list-style-type: none"> <li>• Advise senior management team of the combined liability insurance renewal process for the coming year and seek nominated representatives from each Business Unit.</li> <li>• 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.</li> <li>• Prior year liability submission is broken down into sections to send to the updating officer.</li> </ul>
<b>January</b>	<ul style="list-style-type: none"> <li>• Liability underwriting submission is sent to updating officers requesting that the section be reviewed, updated as appropriate and new information is provided accordingly.</li> <li>• Any changes to updating officers are noted and updated on the spreadsheet.</li> </ul>
<b>April</b>	<ul style="list-style-type: none"> <li>• Prepare current year liability submission.</li> <li>• Ensure that the Business' responses are accurate and that there is a consistency of writing format of the submission.</li> <li>• Link into the annual report to ensure consistency in reporting.</li> <li>• Receive updates from the Business and update the spreadsheet.</li> <li>• Review company documentation and external data to support liability submission.</li> <li>• Review undertaken of liability submission by Corporate Risk team.</li> </ul>
<b>May</b>	<ul style="list-style-type: none"> <li>• Send out annual report to insurance underwriters.</li> <li>• Final review undertaken of the liability submission by the Corporate Risk team.</li> <li>• Review and signoff by the Senior Management Team on liability submission.</li> <li>• Liability submission sent to printer for proofing.</li> <li>• Liability strategy meeting with insurance broker.</li> </ul>
<b>June</b>	<ul style="list-style-type: none"> <li>• Final copy of the liability underwriting submission received from the printer.</li> <li>• Distribute the liability underwriting submission to insurance underwriters around the world through the insurance broker.</li> <li>• Complete insurance documentation for the Bermuda market.</li> </ul>
<b>July</b>	<ul style="list-style-type: none"> <li>• Participate in the marketing liability roadshow in the major insurance markets around the world.</li> <li>• Meet with current and prospective insurance underwriters.</li> </ul>
<b>August</b>	<ul style="list-style-type: none"> <li>• Participate in the Australian insurance market roadshow.</li> <li>• Prepare risk Management and Compliance Committee papers.</li> </ul>

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<b>September</b>	<ul style="list-style-type: none"> <li>• Review quotations and insurance options provided by the insurance broker.</li> <li>• Ensure that insurance underwriters meet the credit rating criteria per company credit policy.</li> <li>• Ensure that appropriate senior management approvals are received for the placement of the insurance.</li> <li>• Ensure insurance is placed and that Business risk exposure is mitigated.</li> <li>• Review of process undertaken and identification of improvement opportunities for the next year.</li> </ul>
<b>October</b>	<ul style="list-style-type: none"> <li>• Payment of invoices</li> </ul>

**Table 6.7 Powercor Australia's Insurance Renewal Process**

Powercor Australia will accept a step change that reflects the difference between its 2009 and 2010 external insurance. However, since Powercor Australia will not have its actual insurance premiums until September 2010, for the purposes of this Revised Regulatory Proposal Powercor Australia 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
<b>Insurance step change</b>	437	437	437	437	437	2,183

**Table 6.8 Insurance step change**

### **6.5.10 Step change – Electricity Safety (Electric Line Clearance) Regulations 2010**

#### **6.5.10.1 Powercor Australia's Initial Regulatory Proposal**

In Chapter 6 of its Initial Regulatory Proposal, Powercor Australia proposed a step change for the costs of complying with the 2005 Line Clearance Regulations and 2005 Line Clearance Code.

Powercor Australia only set out the step change costs of complying with the requirements of the 2005 Line Clearance Regulations and the 2005 Line Clearance Code in respect of LBRA. The step change cost was mischaracterised as a cost of complying with the 2005 Line Clearance Code in LBRA without the exemption from Code requirements granted by the ESV in December 2005. However, the step change cost was actually proposed for the costs of achieving compliance with the 2005 Line Clearance Regulations in LBRA with the exemption. This is explained further below. Further, in calculating those step change costs, Powercor Australia made an error which is corrected in this Revised Regulatory Proposal.

Powercor Australia omitted in its Initial Regulatory Proposal to identify the step change costs associated with complying with the 2005 Line Clearance Regulations and the 2005 Line Clearance Code without the exemption in respect of HBRA.

In addition, the 2010 Line Clearance Regulations and Code replaced the 2005 Line Clearance Regulations and Code on 29 June 2010. In its Initial Regulatory Proposal of 30 November 2009 Powercor Australia did not propose a step change for changes in costs of complying with the 2010 Line Clearance Regulations and Code as they had not yet been released for public comment. Rather, Powercor Australia proceeded on the assumption, expressly stated in the Initial Regulatory Proposal, 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, Powercor Australia provided the AER with estimates of the cost impact of the then proposed Regulations.

Since that time, the 2010 Line Clearance Regulations and 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 Powercor Australia's costs of complying with the 2010 Line Clearance Regulations and 2010 Line Clearance 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.<sup>368</sup> 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

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<sup>368</sup> AER, Draft Determination, Appendix L, p162.



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).

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.<sup>369</sup>

The AER calculated a negative step change of -\$17.1 million for Powercor Australia.<sup>370</sup>

### **6.5.10.3 Powercor Australia's response to AER's Draft Determination**

Powercor Australia's detailed response to the AER's Draft Determination is contained in Appendix 6.1 to this Revised Regulatory Proposal. In that response, Powercor Australia:

- explains that the AER cannot rely on the cost impact analysis in the Line Clearance RIS<sup>371</sup> 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;<sup>372</sup>
- 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, Powercor Australia'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.<sup>373</sup> VEMCO has provided a letter dated 13 July 2010 to Powercor Australia in respect of the cost increases above 2009 actual costs that will apply over the years from January 2011 to December 2015.<sup>374</sup> Since VEMCO is engaged by Powercor Australia to undertake vegetation clearance in accordance with the 2010 Line Clearance Regulations, these costs reflect the increased costs Powercor Australia will be required to pay under the 2010 Line Clearance Regulations. Powercor Australia submits that the AER should accept those step change costs as reasonably reflecting the opex criteria.

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<sup>369</sup> AER, Draft Determination, Appendix L, p170.

<sup>370</sup> AER, Draft Determination, Appendix L, p171.

<sup>371</sup> Attachment 241 to this Revised Regulatory Proposal.

<sup>372</sup> Meeting with the AER, ESV and Victorian DNSPs on 13 July 2010.

<sup>373</sup> Attachment 244 to this Revised Regulatory Proposal.

<sup>374</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).



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Powercor Australia has revised its Initial Regulatory Proposal to include the following step change costs in respect of vegetation clearance.

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
Vegetation Clearance (HBRA)	8,200	7,300	5,600	4,400	3,300	<b>28,800</b>
Vegetation clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – lines from pole to pole	2,896	2,896	2,896	2,896	2,896	<b>14,481</b>
Vegetation clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – service lines from pole to building	4,199	4,199	4,199	4,199	4,199	<b>20,996</b>
Vegetation clearance (omission of clauses 10(b) and (c) and tables 10.2 and 10.3)	2,475	2,475	1,485	1,485	1,485	<b>9,405</b>
Vegetation Clearance (larger LBRA clearance spaces)	1,460	1,460	1,460	1,460	1,460	<b>7,300</b>
Vegetation Clearance (notification and consultation)	(2)	(2)	(2)	(2)	(2)	<b>(8)</b>
Vegetation Clearance (clause 2(3) native trees)	0	764	1,019	2,038	2,547	<b>6,368</b>
Vegetation Clearance (habitat trees)	100	100	100	100	100	<b>500</b>
Vegetation Clearance (LBRA)	2,187	2,038	(83)	(892)	0	<b>3,250</b>
<b>Total Vegetation Clearance Step Change</b>	<b>21,516</b>	<b>21,231</b>	<b>16,675</b>	<b>15,685</b>	<b>15,986</b>	<b>91,093</b>

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 Powercor Australia's Initial Regulatory Proposal

In its Initial Regulatory Proposal, Powercor Australia proposed a \$10,255,000 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.<sup>375</sup> 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.

<sup>375</sup> Initial Regulatory Proposal, p177.

#### **6.5.11.2 Powercor Australia's response to the AER's Draft Determination**

In its Draft Determination, the AER concluded that Powercor Australia had not justified that it required additional opex, above that expended in the 2009 base year to achieve compliance with their ESMS.<sup>376</sup>

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 Victorian DNSPs and that any additional costs would be borne in the current regulatory control period.<sup>377</sup>

#### **6.5.11.3 AER's Draft Determination**

Powercor Australia 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. Powercor Australia assumes that the ESV will honour this position when deciding whether or not to approve ESMSs.

Powercor Australia 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 – At risk townships**

#### **6.5.12.1 Powercor Australia's Initial Regulatory Proposal**

In Chapter 6 of its Initial Regulatory Proposal, Powercor Australia proposed a \$22 million (\$2010) step change to undertake prudent measures to reduce the fire risk posed by distribution assets in areas identified in the Victorian Government's 'at risk townships' protection plans initiative.<sup>378</sup>

On 7 February 2009, Victoria suffered the most devastating bushfires ever to occur in the State. On the advice of fire agencies, as part of its response to the events of 7 February 2009, the Victorian Government announced its intention to establish individual township protection plans for 52 towns and communities within 25 local government areas over and above standard municipal fire prevention plans.

Thirty eight of these towns are located in Powercor Australia's service territory. Six of those towns are already captured within the areas treated under the existing enhanced bushfire mitigation program. Powercor Australia is working with the communities and fire agencies on a number of initiatives, over and above its existing bushfire mitigation programs targeted at providing even greater protection for the towns identified by the Victorian Government.

The anticipated benefits of the program are to reduce as far as practicable the risk of fires caused by asset failure or vegetation impacting on power lines.<sup>379</sup>

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<sup>376</sup> AER, Draft Determination, Appendix L, p159.

<sup>377</sup> AER, Draft Determination, Appendix L, p158.

<sup>378</sup> Initial Regulatory Proposal, p174.

<sup>379</sup> See attachment to email from Powercor Australia to AER dated 8 February 2010.

### **6.5.12.2 AER's Draft Determination**

The AER decided that Powercor Australia's at risk townships proposal did not reasonably reflect the opex criteria.<sup>380</sup>

The AER dismissed the step change proposed by Powercor Australia on the grounds that:

- the at risk township protection plans did not impose an obligation on Powercor Australia to undertake specific fire mitigation strategies;
- Powercor Australia could choose to undertake the at risk townships proposal through self financing arrangements; and
- Powercor Australia's proposal pre-empted the recommendations of the Bushfires Royal Commission and the Victorian Government's response to these recommendations. The AER stated that if the Victorian Government imposes new regulatory requirements on the Victorian DNSPs due to the recommendations of the VBRC or other processes, the DNSPs may seek the approval of the AER to pass through to distribution network users a positive pass through amount.

### **6.5.12.3 Powercor Australia's response to AER's Draft Determination**

Powercor Australia does not contest there is no regulatory obligation on Powercor Australia to undertake the program. This is recognised by the AER in the Draft Determination.<sup>381</sup> However, just because there is no regulatory obligation specifying the requirement on Powercor Australia, does not mean the program is not prudent or without merit.

Powercor Australia developed its program to complement the Victorian Government's initiatives. The program complements the Victorian Government's program in that it is targeted at the towns considered of greatest bushfire risk and it seeks to actively ameliorate the risk faced by the residents of these towns from potential fire risks created by distribution assets.

Powercor Australia believes in light of community expectations, a prudent operator would undertake a program such as that proposed. A prudent operator would consider the risk of ignoring the Victorian Government's initiatives to the community and assess the resultant risk to it of not putting in place a program, including potential legal actions and community backlash. In fact, in 2010 Powercor Australia commenced implementing this program.

Clause 3.1 of the Distribution Code places an onus on Powercor Australia to operate its network in accordance with the concept of 'good electricity industry practice'. This requires Powercor Australia to determine the maintenance practices that best meet the needs of its customers and network rather than leaving this to the government to determine through legislation. Thus the absence of legislated maintenance practices is not sufficient grounds for the AER to dismiss this program. Indeed, Nuttall Consulting

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<sup>380</sup> AER, Draft Determination, Appendix L, p232.

<sup>381</sup> AER, Draft Determination, Appendix L, p232.

noted the benefits of this program are likely to be material.<sup>382</sup>

The AER stated that it considered Powercor Australia could self finance the program irrespective of whether it receives funding from the AER. This statement appears linked to the operation of the EBSS in view of the comments made by Nuttall Consulting on this step change. Such an inference is flawed in that the EBSS can only justify additional expenditure where the benefits of that expenditure accrue to the DNSP. If this is not the case, the DNSP will incur a double penalty. Firstly through returns below those deemed efficient (as the expenditure is not incorporated into the revenue requirement) and secondly, through a negative carryover. As is noted by Powercor Australia in its email to the AER of 5 March 2010, the benefits arising from the program are in the form of reducing, as far as practicable, the risk of fires caused by asset failure or vegetation impacting on power lines which benefits accrue to customers.

Powercor Australia provided the AER with its cost build up model for this step change by email on 8 February 2010.<sup>383</sup>

Since its Initial Regulatory Proposal, Powercor Australia has further developed the benefits case for the at risk township program. Powercor Australia's analysis shows that the base case benefits case has a NPV of \$12.4 million over 20 years. In assessing the benefits case Powercor Australia developed a number of scenarios to test for sensitivity around the benefits case. Of the ten sensitivity tests undertaken, eight of the scenarios had a positive net present value over 20 years. The scenarios which resulted in negative net present values were based on aggressive assumptions. In one of the scenarios which resulted in a negative net present value an aggressive assumption was made with respect to the reduction in fire starts such that it was assumed that fire starts would reduce by 20 per cent. In the other scenario which resulted in a negative net present value an aggressive assumption was made with respect to the reduction in the consequences of fire starts such that it was assumed that this would reduce by 20 per cent.

In assessing whether the expenditure is prudent and efficient Powercor Australia considers that the regulatory test principle should be adopted being that since the base case and majority of sensitivity analyses have a positive NPV, the expenditure can be viewed as prudent and efficient.

The results of this benefits analysis are described in an internal report prepared by Powercor Australia entitled Business Case for Enhanced Asset Management of At Risk Townships protection plans.<sup>384</sup> The Business Case also describes the methodology used to quantify the future potential risks. The Business Case observes that Powercor Australia's risk assessment and cost-benefit analysis has identified an existing risk in terms of the likelihood and value of consequences associated with asset failures associated with at risk townships and a trend that indicates emerging issues and an increasing risk to Powercor Australia's network and the health and safety of

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<sup>382</sup> Nuttall Consulting, Capital Expenditure – Victorian Electricity Distribution Revenue Review, 26 May 2010, p346.

<sup>383</sup> Attachment 251 to this Revised Regulatory Proposal.

<sup>384</sup> Powercor Australia, Business Case for Enhanced Asset Management of At Risk Townships protection plans, 15 July 2010 (Attachment 250 to this Revised Regulatory Proposal).

communities.<sup>385</sup> It recommends that Powercor Australia allow for an increase in opex to implement an enhanced asset management strategy for the at risk townships.

The enhanced asset management activities considered in the Business Case at the thirty eight townships involve:<sup>386</sup>

- pre summer vegetation clearing;
- planned line condition audits;
- ground based vegetation inspections;
- LIDAR (vegetation line clearance inspection audit); and
- ground clearing around fused installations.

The Business Case excluded a number of research activities on the basis that there was no guarantee that these research projects will proceed to implementation and the implementation costs and potential benefits were unknown.<sup>387</sup>

The AER also dismissed the program on the basis that it pre-empts the Bushfires Royal Commission and the Victorian Government's response to the Bushfires Royal Commission. Powercor Australia would again reiterate that it has an obligation under clause 3.1 of the Distribution Code to use 'good asset management'. As noted in the Distribution Code, 'good asset management' is designed to encourage innovation in the provision of distribution services and not prescribe distributor's practices in detail. Further, the Bushfires Royal Commission recommendations are not expected to be released until the second half of 2010. Following their release it will take a period of time for the Victorian Government to consider its response and then, if necessary, put in place legislation. Based on similar legislative changes, it would not be unexpected that the relevant changes could take years rather than months to be implemented.

However, the opportunity to mitigate some of the fire risks posed by distribution assets around at risk townships exists today. Powercor Australia questions the AER's decision that the community should sit back and wait for the 'cogs of government' to turn. The AER has not cited, and Powercor Australia is not aware, of any legislative reason why the AER has to wait until the Victorian Government implements its response. Indeed, it would appear imprudent of the AER not to consider the program at this time.

There is also a discussion in the Draft Determination that infers Powercor Australia can seek a pass through for recommendations arising from the Bushfires Royal Commission.<sup>388</sup> This is not necessarily the case. The AER has rejected the Bushfires Royal Commission as a nominated pass through event.<sup>389</sup> Instead it states it is 'possible' the Bushfires Royal Commission may qualify as a regulatory change or service standard pass through event. In adopting such a position, the AER has afforded no certainty at all to DNSPs that the Bushfires Royal Commission would be considered

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<sup>385</sup> Powercor Australia, Business Case for Enhanced Asset Management of At Risk Townships protection plans, 15 July 2010 (Attachment 250 to this Revised Regulatory Proposal), p2.

<sup>386</sup> Powercor Australia, Business Case for Enhanced Asset Management of At Risk Townships protection plans, 15 July 2010 (Attachment 250 to this Revised Regulatory Proposal), p2.

<sup>387</sup> The costs of these research projects was forecast as \$450,000 per annum in the model provided by Powercor Australia to the AER on 8 February 2010 (Attachment 251 to this Revised Regulatory Proposal).

<sup>388</sup> AER, Draft Determination, Appendix L, p232.

<sup>389</sup> AER, Draft Determination, p710.



a pass through event and as such, Powercor Australia can place no reliance on the AER's comments on this matter. This is particularly so given the AER's erroneous interpretation of a regulatory change event in its Draft Determination (where the AER confines it to changes in existing regulations), which means there is a greater risk that recommendations arising from the Bushfires Royal Commission will not qualify as a regulatory change event. Powercor Australia discusses this pass through issue further in the Chapter 17 of this Revised Regulatory Proposal.

Powercor Australia, as noted in its Initial Regulatory Proposal, is committed to the at risk townships program. Powercor Australia has already commenced implementing this program. The program has been incorporated in its on-going bushfire mitigation activities and has also been included in Powercor Australia's insurance liability underwriting submission for 2010/11.

Powercor Australia has also reviewed the comments made by Nuttall Consulting in reference to the at risk townships program.<sup>390</sup> In relation to those comments Powercor Australia provides the following response:

- Powercor Australia rejects that the proposed expenditure calculations were provided at a 'high level'. Powercor Australia refers the AER to Attachment A to its email of 8 February 2010 which set out how the step change costs were developed and the sources of information underlying the step change and, accordingly, are of no relevance to research and development undertaken as part of the at risk townships program;
- Nuttall Consulting discredited the research and development component of the program (which comprised less than 12 per cent of the total program) on the basis it would fund itself through the EBSS. Powercor Australia would again refer the AER to the discussion above that the EBSS will only provide an incentive where the benefits accrue to the DNSP. The ESCV comments noted by Nuttall Consulting referred to research and development targeted at creating internal efficiencies within DNSPs;
- Nuttall Consulting formed the view expenditures associated with line surveys, LIDAR and independent asset audits should be removed. The Nuttall Consulting report provides no basis for this view.
- Nuttall Consulting also expressed the view that the fact that SP AusNet has not put up a step change in relation to at risk townships, this in some way discredits the Powercor Australia program. Powercor Australia would question the opex factor or criteria this judgment was based on. Whether SP AusNet put up a step change in relation to at risk townships has no relevance to the AER's assessment of Powercor Australia's forecast opex in accordance with the opex criteria.

For the above reasons, Powercor Australia submits that the AER should accept Powercor Australia's step change for the at risk townships program. Powercor Australia'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 Powercor Australia's Initial Regulatory Proposal.

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<sup>390</sup> Nuttall Consulting, Capital Expenditure – Victorian Electricity Distribution Revenue Review, 26 May 2010, pp344-6.



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	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>At risk townships step change</b>	3,847	3,847	3,847	3,847	3,847	<b>19,235</b>

Table 6.10 Step change – At risk townships

### **6.5.13 Step change – Communications in extreme supply events**

#### **6.5.13.1 Powercor Australia's Initial Regulatory Proposal**

In its presentation to the AER on 28 January 2010, Powercor Australia informed the AER of an additional proposed step change in respect of communications in extreme supply events. In its letter dated 4 March 2010, Powercor Australia informed the AER that its estimated costs of this step change were \$0.4 million per annum (\$2 million in total).

The step change arose as a result of the ESCV's Extreme Supply Events Decision. Accordingly, it arose after Powercor Australia 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.<sup>391</sup> 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 Powercor Australia's proposed step change.

#### **6.5.13.3 Powercor Australia'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.<sup>392</sup>

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);

<sup>391</sup> AER Draft Determination, pp197-200.

<sup>392</sup> ESC, Final Amendments to the Electricity Distribution Code and the Energy Retail Code, 24 February 2010 (Attachment 126 to this Revised Regulatory Proposal).

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- 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.<sup>393</sup>

Since the amendments to the Distribution Code came into effect, Powercor Australia 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
<b>Step change costs for communications in extreme supply events</b>	686	686	686	686	686	3,430

**Table 6.11 Communications in extreme supply events step change**

The breakdown of these costs is provided as an attachment to this Revised Regulatory Proposal.<sup>394</sup> 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.

Powercor Australia 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 Powercor Australia 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. Powercor Australia 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:

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<sup>393</sup> ESCV, Distribution Code (Attachment 127 to this Revised Regulatory Proposal).

<sup>394</sup> Attachment 128 to this Revised Regulatory Proposal.

- 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 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 Powercor Australia 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 Powercor Australia's response to AER's Draft Determination**

As the AER would be aware through the information exchange process that followed the lodging of Powercor Australia's Initial Regulatory Proposal, the information sought above is not readily available from within Powercor Australia'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, Powercor Australia cannot continue to devote up to ten full time resources to collecting information not used internally within Powercor Australia.

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 Powercor Australia.

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Based on Powercor Australia'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 Powercor Australia's existing reporting systems and resourcing.

Powercor Australia 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 Powercor Australia will be required to periodically audit the information being provided and subject any information being provided to the AER to legal review.

Powercor Australia 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 Powercor Australia 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, Powercor Australia 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.

Powercor Australia 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 Powercor Australia'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 Powercor Australia'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.<sup>395</sup> The total costs have been apportioned evenly between CitiPower and Powercor Australia.

Accordingly, Powercor Australia proposes the following step change for that expenditure:

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<sup>395</sup> Cost build up model for outcomes monitoring and compliance step change (Attachment 130 to this Revised Regulatory Proposal).

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	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Step change costs for outcomes monitoring and compliance</b>	665	60	60	60	60	905

Table 6.12 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.<sup>396</sup>

#### 6.5.15.2 Powercor Australia'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.<sup>397</sup> 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, Powercor Australia considers that the AER must compensate it for the additional costs it will incur. Accordingly, Powercor Australia has proposed a step change for that expenditure.

Powercor Australia considers that, if the AER does not alter this requirement in the procedures for assigning or reassigning customers to tariff classes, Powercor Australia's forecast step change would:

- properly be categorised as being triggered by a change in Powercor Australia's regulatory obligations, as Powercor Australia's obligations under the ESCV's 2006-10 EDPR do not require this expenditure; and
- reasonably reflect the efficient costs a prudent operator in Powercor Australia'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, Powercor Australia proposes the following step change for that expenditure:

<sup>396</sup> AER, Draft Determination, Appendix G, p21.

<sup>397</sup> Clause 2.1.20 of the ESCV's 2006-10 EDPR (Attachment 32 to this Revised Regulatory Proposal).

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	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
Tariff assignment step change	1,016	330	330	330	330	2,337

Table 6.13 Tariff assignment step change

Powercor Australia observes that the AER will not need to allow Powercor Australia 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, Powercor Australia 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, Powercor Australia 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, Powercor Australia submits that if the AER rejects its proposed WAPC or side constraint terms (or both of them) regarding transmission-related costs, the 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 Powercor Australia's Revised Regulatory Proposal

Powercor Australia 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;<sup>398</sup>
- 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;<sup>399</sup>
- the AER's decision in respect of Powercor Australia's proposed step change for self insurance;<sup>400</sup>
- the AER's decision in respect of Powercor Australia's proposed step change for climate change;<sup>401</sup>

<sup>398</sup> AER, Draft Determination, p243.

<sup>399</sup> AER, Draft Determination, p246.

<sup>400</sup> AER, Draft Determination, Appendix M.

<sup>401</sup> AER, Draft Determination, Appendix L, p186.



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- the AER's decision in respect of Powercor Australia's proposed step change for compliance with the Electricity Safety Management Regulations;<sup>402</sup>
- the AER's decision in respect of Powercor Australia's proposed step change for the national framework for distribution network planning and expansion;<sup>403</sup>
- the AER's decision in respect of Powercor Australia's proposed step change in respect of the customer charter;<sup>404</sup> and
- the AER's decision to include a step change for Powercor Australia in respect of regulatory submission costs.<sup>405</sup>

Powercor Australia 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 Powercor Australia's distribution licence fee of \$302,995;
- 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;
- 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 its at risk townships program 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;

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<sup>402</sup> AER, Draft Determination, Appendix L, p159.

<sup>403</sup> AER, Draft Determination, Appendix L, p197;

<sup>404</sup> AER, Draft Determination, Appendix L, p203.

<sup>405</sup> AER, Draft Determination, Appendix L, p208.

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- 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.

Powercor Australia'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 Powercor Australia's building block proposal are listed in Appendix 1.1 to this Revised Regulatory Proposal.

The table below shows the calculation of Powercor Australia's revised proposed 2010 base opex the 2010-15 regulatory control period.

	(\$'000, \$2010)
<b>2009 O&amp;M per Regulatory Accounts</b>	126,588
<b>Provision adjustments</b>	4,874
<b>Licence fee</b>	(307)
<b>ATO audit</b>	(1,978)
<b>GSLs</b>	(1,813)
<b>Superannuation</b>	0
<b>Price Review</b>	(2,083)
<b>2010 Benchmark Efficiency</b>	4,361
<b>Total</b>	<b>129,641</b>

Table 6.14 Powercor Australia's revised proposed 2010 base opex

The table below shows Powercor Australia's revised proposed forecast total operating and maintenance costs the 2010-15 regulatory control period.

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	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>2010 Base O&amp;M</b>	129,641	129,641	129,641	129,641	129,641	<b>648,205</b>
<b>Step changes (excluding margins, escalation &amp; overheads)</b>	34,790	33,064	29,189	31,175	32,393	<b>160,611</b>
<b>Change in overhead transfers (excluding margins and escalation)</b>	(914)	(1,043)	(1,237)	(985)	(884)	<b>(5,063)</b>
<b>Input escalation (on above costs)</b>	3,953	8,561	12,218	15,177	18,139	<b>58,048</b>
<b>Scale escalation (on above costs)</b>	1,507	3,648	5,551	7,788	10,227	<b>28,721</b>
<b>Margins (on above costs)</b>	6,611	6,948	7,231	7,520	7,804	<b>36,114</b>
<b>Total</b>	<b>175,588</b>	<b>180,819</b>	<b>182,591</b>	<b>190,316</b>	<b>197,320</b>	<b>926,634</b>

Table 6.15 Powercor Australia's revised proposed forecast total opex

The following table shows Powercor Australia's proposed step changes, including escalation, margins and overheads where relevant.

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Direct costs</b>						
Customer Charter	743	-	-	-	-	<b>743</b>
AEMC Framework Distribution Planning	863	940	748	863	862	<b>4,276</b>
At Risk Victorian Towns	3,847	3,847	3,847	3,847	3,847	<b>19,235</b>
Communications in extreme supply events	686	686	686	686	686	<b>3,430</b>
Vegetation clearance (compliance with Line Clearance Regulations)	21,516	21,231	16,675	15,685	15,986	<b>91,093</b>
Insurance	437	437	437	437	437	<b>2,183</b>
Tariff assignment	1,016	330	330	330	330	<b>2,337</b>
Demand incentive allowance	600	600	600	600	600	<b>3,000</b>
GSL payments	1,152	1,152	1,152	1,152	1,152	<b>5,761</b>
Regulatory submission costs	-	-	149	2,083	1,775	<b>4,007</b>
Superannuation	77	306	741	1,389	2,337	<b>4,851</b>
Outcomes monitoring and compliance	665	60	60	60	60	<b>905</b>
Overhead transfers	(914)	(1,043)	(1,237)	(985)	(884)	<b>(5,063)</b>
Debt Raising Costs	3,187	3,475	3,764	4,043	4,321	<b>18,791</b>
<b>Total</b>	<b>33,876</b>	<b>32,021</b>	<b>27,951</b>	<b>30,191</b>	<b>31,509</b>	<b>155,548</b>
<b>Escalation</b>						
Customer Charter	17	-	-	-	-	<b>17</b>
AEMC Framework Distribution Planning	31	78	94	138	167	<b>507</b>
At Risk Victorian Towns	119	273	401	502	604	<b>1,899</b>
Communications in extreme supply events	15	32	42	49	58	<b>196</b>
Vegetation clearance (compliance with Line Clearance Regulations)	-	-	-	-	-	<b>-</b>
Insurance	-	-	-	-	-	<b>-</b>
Tariff assignment	-	-	-	-	-	<b>-</b>

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Demand incentive allowance	-	-	-	-	-	-
GSL payments	21	43	65	86	106	321
Regulatory submission costs	-	-	9	148	150	307
Superannuation	-	-	-	-	-	-
Outcomes monitoring and compliance	-	-	-	-	-	-
Overhead transfers	-	-	-	-	-	-
Debt Raising Costs	-	-	-	-	-	-
<b>Total</b>	<b>203</b>	<b>426</b>	<b>611</b>	<b>923</b>	<b>1,085</b>	<b>3,247</b>
<b>Overheads</b>						
Customer Charter	-	-	-	-	-	-
AEMC Framework Distribution Planning	-	-	-	-	-	-
At Risk Victorian Towns	368	376	391	409	417	1,961
Communications in extreme supply events	-	-	-	-	-	-
Vegetation clearance (compliance with Line Clearance Regulations)	1,996	1,936	1,536	1,476	1,498	8,441
Insurance	-	-	-	-	-	-
Tariff assignment	-	-	-	-	-	-
Demand incentive allowance	-	-	-	-	-	-
GSL payments	-	-	-	-	-	-
Regulatory submission costs	-	-	-	-	-	-
Superannuation	-	-	-	-	-	-
Outcomes monitoring and compliance	-	-	-	-	-	-
Overhead transfers	-	-	-	-	-	-
Debt Raising Costs	-	-	-	-	-	-
<b>Total</b>	<b>2,363</b>	<b>2,312</b>	<b>1,927</b>	<b>1,885</b>	<b>1,915</b>	<b>10,402</b>
<b>Margins</b>						
Customer Charter	-	-	-	-	-	-
AEMC Framework Distribution Planning	-	-	-	-	-	-
At Risk Victorian Towns	32	32	32	34	34	163
Communications in extreme supply events	-	-	-	-	-	-
Vegetation clearance (compliance with Line Clearance Regulations)	176	174	140	137	141	769
Insurance	-	-	-	-	-	-
Tariff assignment	-	-	-	-	-	-
Demand incentive allowance	-	-	-	-	-	-
GSL payments	-	-	-	-	-	-
Regulatory submission costs	-	-	-	-	-	-
Superannuation	-	-	-	-	-	-
Outcomes monitoring and compliance	-	-	-	-	-	-
Overhead transfers	-	-	-	-	-	-
Debt Raising Costs	-	-	-	-	-	-
<b>Total</b>	<b>208</b>	<b>206</b>	<b>173</b>	<b>171</b>	<b>175</b>	<b>931</b>
<b>Total</b>						
Customer Charter	760	-	-	-	-	760
AEMC Framework Distribution Planning	894	1,018	842	1,001	1,029	4,783
At Risk Victorian Towns	4,366	4,527	4,672	4,791	4,902	23,257
Communications in extreme supply events	701	718	728	735	744	3,626

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Vegetation clearance (compliance with Line Clearance Regulations)	23,688	23,341	18,351	17,297	17,625	<b>100,302</b>
Insurance	437	437	437	437	437	<b>2,183</b>
Tariff assignment	1,016	330	330	330	330	<b>2,337</b>
Demand incentive allowance	600	600	600	600	600	<b>3,000</b>
GSL payments	1,173	1,195	1,217	1,238	1,259	<b>6,082</b>
Regulatory submission costs	-	-	158	2,232	1,925	<b>4,314</b>
Superannuation	77	306	741	1,389	2,337	<b>4,851</b>
Outcomes monitoring and compliance	665	60	60	60	60	<b>905</b>
Overhead transfers	(914)	(1,043)	(1,237)	(985)	(884)	<b>(5,063)</b>
Debt Raising Costs	3,187	3,475	3,764	4,043	4,321	<b>18,791</b>
<b>Total</b>	<b>36,650</b>	<b>34,964</b>	<b>30,663</b>	<b>33,169</b>	<b>34,683</b>	<b>170,128</b>

**Table 6.16 Powercor Australia's proposed step changes (including escalation, overheads and margins)**

## **7. SCALE ESCALATION**

In this Chapter of the Revised Regulatory Proposal, Powercor Australia responds to section 7.5.5 of, and Appendix J to, the AER's Draft Determination regarding Powercor Australia's proposed scale escalation of its opex forecast.

### **7.1 Summary of key points**

While Powercor Australia accepts the AER's use of a composite growth factor based on physical metrics as a network growth driver, Powercor Australia 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, Powercor Australia considers that a network growth escalator based on the simple average of growth in line length, transformers and **installed zone substation capacity** is appropriate.

Powercor Australia 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, Powercor Australia includes in this Revised Regulatory Proposal an updated customer growth escalator, which reflects current customer growth forecasts based on more recent macro economic data.

Powercor Australia 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). Powercor Australia has also adopted the AER's economies of scale adjustment of 50 per cent for the 'Quality audits' opex category (function code 482).

However, Powercor Australia maintains that its remaining economies of scale adjustments, and its application of these adjustments, are reasonable.

Powercor Australia 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. Powercor Australia 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 Powercor Australia, 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 Powercor Australia's network, which implies that Powercor Australia's opex should be expected to increase (rather than decrease) in the next regulatory control period. Acting conservatively, however, Powercor Australia 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**

Powercor Australia 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 Powercor Australia'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, Powercor Australia applied one of three proposed scale escalators (or scale drivers) to a number of opex categories that were identified as being driven by growth.<sup>406</sup> The scale escalators applied were:

- network growth – to take into account growth in the size of the distribution network. Powercor Australia'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.

Powercor Australia engaged an independent expert, SKM, to examine the derivation of the scale escalators. SKM was satisfied with the calculation methodology utilised for each escalator.<sup>407</sup>

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 Powercor Australia'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,<sup>408</sup> Powercor Australia 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 Powercor Australia were determined by SKM, adopting the approach previously used by ElectraNet and ETSA.<sup>409</sup>

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

<sup>406</sup> Initial Regulatory Proposal, pp160-1.

<sup>407</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), pp9-10.

<sup>408</sup> 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.

<sup>409</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11.

reduction to the scale escalation amount for the identified opex category to account for economies of scale.<sup>410</sup>

### **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 Powercor Australia 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.

Powercor Australia 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.<sup>411</sup> SKM supported the approach of applying scale escalators to input cost escalated forecasts.<sup>412</sup>

SKM also reviewed the application of the economies of scale adjustments to the opex categories.<sup>413</sup> SKM found that Powercor Australia's application (also set out in Appendix A to SKM's report) was reasonable.<sup>414</sup>

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 and control	Network growth	5%
313	Emergency faults - public lighting	Customer growth	5%
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 plant routine & defect maintenance	Network growth	5%
319	Distribution system plan breakdown maintenance	Network growth	5%
321	System planning contingencies	Network growth	75%

<sup>410</sup> 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.

<sup>411</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

<sup>412</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), pp1, 13.

<sup>413</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

<sup>414</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

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<b>Function code</b>	<b>Operating and maintenance activity</b>	<b>Scale escalator</b>	<b>Economies of scale adjustment</b>
322	System operators	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	5%
410	Insulator washing	Network growth	5%
425	Environmental management	Network growth	90%
426	Bushfire mitigation	Network growth	5%
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	5%
477	Customer 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%
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 & administration	Work volume	90%
505	Quality accreditation	Network growth	90%
506	Engineering & technical services	Network growth	75%

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Function code	Operating and maintenance activity	Scale escalator	Economies of scale adjustment
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%
605	Work completed by PCA CP	Work volume	90%
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%
<b>Meter Data Services</b>			
	FRC/MDS/CIS	Customer growth	90%
	FRC/MDS/CIS - AMI	Customer growth	90%
	Meter data management	Customer growth	90%
<b>Billing &amp; revenue collection</b>			
	Billing & Rev Collection	Customer growth	5%
<b>Customer service</b>			
	Customer service	Customer growth	50%
<b>Other</b>			
	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 Powercor Australia's Initial Regulatory Proposal**

## **7.4 AER's Draft Determination**

The AER did not accept Powercor Australia'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:<sup>415</sup>

- 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 Powercor Australia for some categories of expenditure<sup>416</sup> and removed all proposed scale escalation from other categories.<sup>417</sup> The AER also stated that it made adjustments to reflect SKM's recommendations regarding the economies of scale adjustments to be made.<sup>418</sup>

The AER indicated in its Draft Determination that an adjustment should be made to Powercor Australia's total opex forecast to reflect its proposed increase in reliability and quality maintained capex (i.e. to reflect the capex/opex trade-off).<sup>419</sup> The AER reduced Powercor Australia'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.<sup>420</sup>

The AER's rejection of Powercor Australia'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.

## **7.5 Powercor Australia's response to the AER's Draft Determination**

### **7.5.1 Scale escalators**

#### **7.5.1.1 Summary**

While Powercor Australia accepts the AER's use of a composite growth factor based on physical metrics as a network growth driver, Powercor Australia 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, Powercor Australia considers that a network growth escalator based on the simple average of growth in line length, transformers and **installed zone substation capacity** is appropriate.

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<sup>415</sup> AER, Draft Determination, p252.

<sup>416</sup> AER, Draft Determination Appendices, Appendix J, pp100-103; AER, spreadsheet titled 'CP\_PAL\_Scale\_Opex\_Economies of Scale\_Draft\_Decision' (provided to Powercor Australia by the AER by email on 24 June 2010).

<sup>417</sup> AER, Draft Determination Appendices, Appendix J, pp101-103; AER, spreadsheet titled 'CP\_PAL\_Scale\_Opex\_Economies of Scale\_Draft\_Decision' (provided to Powercor Australia by the AER by email on 24 June 2010).

<sup>418</sup> AER, Draft Determination Appendices, Appendix J, p100.

<sup>419</sup> AER, Draft Determination Appendices, Appendix J, pp105-107.

<sup>420</sup> AER, Draft Determination Appendices, Appendix J, pp105-7.

Powercor Australia 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, Powercor Australia 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**

Powercor Australia accepts the AER's decision to adopt physical metrics as a driver for network growth. Further, Powercor Australia accepts the AER's decision to calculate the network growth driver by taking the simple average of the physical metrics.

However, Powercor Australia does not accept the AER's selection of physical metrics. While Powercor Australia accepts that growth in line length and growth in the number of distribution transformers may be appropriate measures of network growth, Powercor Australia 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 Powercor Australia 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.<sup>421</sup> SKM observed that:<sup>422</sup>

*'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.'*

Another independent expert engaged by Powercor Australia following the release of the Draft Determination, PB, reached the same view. PB noted that:<sup>423</sup>

*'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*

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<sup>421</sup> 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.

<sup>422</sup> 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.

<sup>423</sup> PB, Letter re Application of network growth scale escalators for opex forecasts, 2 July 2010 (Attachment 134 to this Revised Regulatory Proposal), p2.



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*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.<sup>424</sup>

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,<sup>425</sup> Powercor Australia 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<sup>426</sup>) 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,<sup>427</sup> Powercor Australia is not aware of any expert opinion supporting the use of the number of zone substations as a measure of network growth.

Powercor Australia 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 Powercor Australia is set out in Table 7.3 below.

	Level and Growth %					
	2010	2011	2012	2013	2014	2015
Lines (km) <sup>428</sup>	83,926	85,377	86,875	88,443	90,074	91,725
Lines growth (year on year)		1.73%	1.75%	1.81%	1.84%	1.83%
Distribution transformers	81,095	82,560	84,052	85,571	87,117	88,691
Distribution transformers growth (year on year)		1.81%	1.81%	1.81%	1.81%	1.81%
Installed substation capacity	3,221	3,287	3,419	3,505	3,623	3,755
Installed substation capacity growth (year on year)		2.53%	4.02%	2.50%	3.38%	3.64%
Average growth – bottom up (simple average)		1.86%	2.53%	2.04%	2.34%	2.43%

**Table 7.3 Determination of the network growth escalator applied in Powercor Australia's Revised Regulatory Proposal**

<sup>424</sup> 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.

<sup>425</sup> AER, Draft Determination Appendices, Appendix J, p95.

<sup>426</sup> 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.

<sup>427</sup> 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.

<sup>428</sup> See Revised Regulatory Templates 6.1.

### **7.5.1.3 Work volume**

The AER rejected Powercor Australia's approach to determining a work volume escalator on the basis it was circular.<sup>429</sup>

While SKM, in its review of the AER's Draft Determination, disputes the AER's conclusion that Powercor Australia's proposed work volume growth driver is circular and suggests that the AER undertake a proper review of the escalator,<sup>430</sup> Powercor Australia 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.<sup>431</sup>

### **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.<sup>432</sup> The AER accepted the customer growth escalator proposed by Powercor Australia.<sup>433</sup>

The customer growth escalator applied in Powercor Australia'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**

Powercor Australia 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). Powercor Australia has also adopted the AER's economies of scale adjustment of 50 per cent for the 'Quality audits' opex category (function code 482).

However, Powercor Australia maintains that its remaining economies of scale adjustments, and its application of these adjustments, are reasonable.

As noted above, the adjustments proposed in the Initial Regulatory proposal were considered reasonable by an independent expert, SKM.<sup>434</sup> In addition, Powercor Australia 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,<sup>435</sup> which has, in the main, been accepted by the AER.

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<sup>429</sup> AER, Draft Determination Appendices, Appendix J, p93.

<sup>430</sup> 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.

<sup>431</sup> 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 Powercor Australia by the AER by email on 24 June 2010).

<sup>432</sup> AER, Draft Determination Appendices, Appendix J, p94.

<sup>433</sup> AER, spreadsheet titled 'CP\_PC\_AER\_Scale\_Opex\_Draft\_Decision' (provided to Powercor Australia by the AER by email on 7 June 2010).

<sup>434</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p12.

<sup>435</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11; SKM, Review of AER Draft Decision – Opex Scale Escalation for CitiPower and Powercor Australia, 8 July 2010 (Attachment 133 to this Revised Regulatory Proposal), p1.

In reviewing the economies of scale adjustments made by ETSA, the AER's expert, PB, concluded that:<sup>436</sup>

*'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.<sup>437</sup> For the reasons discussed below, Powercor Australia does not consider that the AER's conclusion in respect of ETSA's escalation of emergency response opex can reasonably be applied to Powercor Australia's proposed escalation of emergency response opex.

Powercor Australia 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);
- salary expenditure (function code 635); and
- vegetation control, insulator washing and bushfire mitigation (function codes 400, 410 and 426).

#### **7.5.2.1 Emergency maintenance**

In its Draft Determination, the AER increased Powercor Australia'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).<sup>438</sup>

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'* and that, as asset replacement capex and preventative and corrective maintenance should directly reduce the level of emergency response opex

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<sup>436</sup> 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.

<sup>437</sup> 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 ETSA's 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.

<sup>438</sup> 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.

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because new or refurbished and maintained assets are less likely to fail, emergency maintenance expenditure arising due to asset failure should not be escalated.<sup>439</sup>

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.<sup>440</sup> 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.<sup>441</sup> Thus, ETSA considered that there was no basis for an increase in the economies of scale adjustment applied to its emergency response opex.<sup>442</sup>

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.<sup>443</sup> 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).<sup>444</sup> As PB noted, *'it is through this mechanism ETSA Utilities has endeavoured to establish the relationship between asset age, defects and associated opex'*.<sup>445</sup>

PB recognised that the increasing weighted average age of key asset classes represented a risk to ETSA and recommended the application of age escalation.<sup>446</sup> While the AER rejected the proposed scale escalation of that proportion of ETSA's emergency response opex that related to asset failure,<sup>447</sup> the AER did so on the basis that it allowed asset age escalation of that opex.<sup>448</sup> 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.

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<sup>439</sup> AER, Draft Determination Appendices, pp100-1; AER, South Australian Draft Determination (Attachment 21 to this Revised Regulatory Proposal), p214.

<sup>440</sup> ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), p120.

<sup>441</sup> ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), p120.

<sup>442</sup> ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), p120.

<sup>443</sup> AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p115.

<sup>444</sup> ETSA, Revised Regulatory Proposal 2010-15, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), pp124-7.

<sup>445</sup> 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.

<sup>446</sup> 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.

<sup>447</sup> AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p115.

<sup>448</sup> 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.

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Subsequent to the Draft Determination, Powercor Australia engaged SKM to consider the average asset age of its network.<sup>449</sup> SKM's analysis suggests that, like ETSA, Powercor Australia'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.<sup>450</sup> Accordingly, Powercor Australia expects its emergency response opex will increase with growth in the network. In contrast to ETSA, Powercor Australia has not proposed an escalator for asset age. The AER cannot, therefore, reject Powercor Australia's scale escalation of emergency response opex on the basis that Powercor Australia has already sought to account for its increasing average network asset age through an age escalator.

Powercor Australia 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. Powercor Australia 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;<sup>451</sup>
- for smaller distribution items (such as hardware associated with poles and wires), it is not economic for Powercor Australia to seek to claim on every warranty; and
- warranty periods generally only extend 12 months, after which time asset failures can, and do, occur,<sup>452</sup> and these failures are not covered by supplier warranties.

In any event, Powercor Australia notes for completeness that the majority of the outages it experiences are the result of exogenous events. This is because most of Powercor Australia's network is overhead. The proportion of outage events due to equipment failure events is set out in Table 7.4 below.

	2006	2007	2008	2009
Equipment failure outage events	14,990	14,917	13,321	7,767
Total number of outage events	37,670	32,968	39,513	19,676
Proportion of outage events due to equipment failure	40%	45%	34%	39%

**Table 7.4 Powercor Australia's outage events 2006-09**

<sup>449</sup> SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal).

<sup>450</sup> SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p4.

<sup>451</sup> Powercor Australia 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.

<sup>452</sup> 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.



### **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.<sup>453</sup> 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).<sup>454</sup> Accordingly, the AER increased the economies of scale adjustment applied to function codes 330 and 338 from 5 per cent to 75 per cent.<sup>455</sup>

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 Powercor Australia's network grows, more poles, distribution transformers and zone substation equipment enter the maintenance system. As a consequence, more asset inspections and routine testing is scheduled. Powercor Australia 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).<sup>456</sup> 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.<sup>457</sup>

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, Powercor Australia 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.<sup>458</sup>

The salary expenditure function code is applied only to salaries earned by Powercor Australia employees in the network business unit of Powercor Australia who do not time confirm (i.e. employees who do not allocate their time by project) and who undertake the following activities:<sup>459</sup>

- control and operations;

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<sup>453</sup> AER, Draft Determination Appendices, Appendix J, p101.

<sup>454</sup> AER, Draft Determination Appendices, Appendix J, p101.

<sup>455</sup> AER, Draft Determination Appendices, Appendix J, p101.

<sup>456</sup> AER, Draft Determination Appendices, Appendix J, pp101-2.

<sup>457</sup> AER, Draft Determination Appendices, Appendix J, pp101-2.

<sup>458</sup> AER, Draft Determination Appendices, Appendix J, pp101-2; AER, spreadsheet titled 'CP\_PAL\_Scale\_Opex\_Economies of Scale\_Draft\_Decision' (provided to Powercor Australia by the AER by email on 24 June 2010).

<sup>459</sup> 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.



- 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.

#### **7.5.2.4 Vegetation control, insulator washing and bushfire mitigation**

The AER's Draft Determination did not explicitly address the AER's changes to Powercor Australia's proposed economies of scale adjustments for vegetation control, insulator washing and bushfire mitigation (function codes 400, 410 and 426).<sup>460</sup> However, the AER's scale adjustments model indicates that the AER increased the economies of scale adjustment applying to each of these codes from 5 per cent to 75 per cent.<sup>461</sup> Powercor Australia observes that this change to the economies of scale adjustment is identical to the change recommended by SKM in respect of CitiPower.<sup>462</sup>

On 29 June 2010, Powercor Australia sought an explanation from the AER in respect of these adjustments.<sup>463</sup> The AER responded to Powercor Australia's request, but did not provide an explanation. Specifically, the AER indicated that it '*recognises the adjustments to these factors were recommended for CitiPower and not Powercor*' and referred Powercor Australia to its email response of 24 June 2010.<sup>464</sup> In the response of 24 June 2010, the AER similarly recognised that SKM's recommendations applied to CitiPower and not Powercor Australia but stated: '*Notwithstanding, the AER's draft decision on relevant matters is contained in appendix J, including the additional adjustments presented in table J.9*'.<sup>465</sup> Powercor Australia therefore understands the AER to be seeking to rely on its explanations in Table J.9 in respect of 'various' expenditure categories.<sup>466</sup> However, there is no reasoning apparent in the 'various' row of Table J.9, other than a reference to the SKM recommendation, which the AER has acknowledged relates only to CitiPower.<sup>467</sup>

Powercor Australia highlights that there is a strong relationship between network growth and the vegetation control, insulator washing and bushfire mitigation operating and maintenance activities.<sup>468</sup> In particular, the volume of work in relation to each of

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<sup>460</sup> AER, Draft Determination Appendices, Appendix J, pp100-103.

<sup>461</sup> AER, spreadsheet titled 'CP\_PAL\_Scale\_Opex\_Economies of Scale\_Draft\_Decision' (provided to Powercor Australia by the AER by email on 24 June 2010).

<sup>462</sup> SKM, Scale Escalators AER Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11.

<sup>463</sup> Email from Powercor Australia to the AER, 29 June 2010.

<sup>464</sup> Email from Peter Betson, AER, 1 July 2010.

<sup>465</sup> Email from Peter Betson, AER, 24 June 2010.

<sup>466</sup> AER, Draft Determination Appendices, Appendix J, p100.

<sup>467</sup> AER, Draft Determination Appendices, Appendix J, p100; Emails from Peter Betson, AER, 24 June 2010 and 1 July 2010.

<sup>468</sup> Vegetation control includes all costs directly associated with management of vegetation to comply with mandatory requirements, outworking any safety scheme, delivering vegetation strategy obligations such as normal

these activities has a direct correlation with line length. For example, growth in line length would mean that more spans were exposed to vegetation and hence vegetation control activities would increase. Similarly, the longer the line length, the more insulators on the network and thus the higher the costs involved in removing dust and pollution. Finally, the longer the line length, the greater the number of spans over which bushfire mitigation activity would need to take place.

Powercor Australia notes that SKM indicated that the increase in the scale of economies adjustments<sup>469</sup> it recommended in respect of CitiPower was appropriate because the CitiPower network 'footprint' was not expanding substantially and that growth would be within the existing footprint.<sup>470</sup> Accordingly, SKM observed that network growth would not add to the line length that drives operating and maintenance costs.<sup>471</sup> This reasoning does not apply in respect of Powercor Australia where the network 'footprint' is continuing to expand and thus the operating and maintenance costs associated with vegetation control, insulator washing and bushfire mitigation are likely to increase broadly in line with network growth and thus a five per cent economies of scale adjustment is appropriate.

### **7.5.3 Application of scale escalators and economies of scale adjustments**

While not addressed in the AER's Draft Determination, Powercor Australia observes that the AER has applied scale escalation independently of input escalation.<sup>472</sup> This approach will lead to an error as the compounding effect of input cost and scale escalation has been ignored.

SKM agreed with Powercor Australia'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.'*<sup>473</sup>

Further, the AER calculated the economies of scale adjustments using the network growth, work volume and customer growth escalators included in Powercor Australia's Initial Regulatory Proposal, rather than its own escalators applied in the Draft Determination.<sup>474</sup> 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.<sup>475</sup> Powercor Australia submits that it is imperative that,

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tree cutting, undergrowth control and debris disposal connected with sub-transmission, HV or LV systems. Insulator washing includes the costs of live-line washing high voltage overhead line insulators to remove dust and pollution. Bushfire mitigation includes the following activities in HBRAs: pre-summer line condition audits; reduction of ground fuel around poles; silicone treatment of overhead line insulators; and audit of vegetation around overhead lines.

<sup>469</sup> That is, to use the language of SKM, the reduction in the economies of scale factors.

<sup>470</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11.

<sup>471</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), p11.

<sup>472</sup> AER, spreadsheet titled 'CP\_PC\_AER\_Scale\_Opex\_Draft\_Decision' (provided to Powercor Australia by the AER by email on 7 June 2010).

<sup>473</sup> SKM, Scale Escalators Model Review for CitiPower and Powercor Australia, 24 November 2009 (Attachment P0093 to the Initial Regulatory Proposal), pp1, 13.

<sup>474</sup> AER, spreadsheet titled 'CP\_PAL\_Scale\_Opex\_Economies of Scale\_Draft\_Decision' (provided to Powercor Australia by the AER by email on 24 June 2010).

<sup>475</sup> This is because Powercor Australia's proposed escalators would have resulted in a larger (gross) increase in opex than the escalators applied in the Draft Determination. Using Powercor Australia's proposed escalators to

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.<sup>476</sup>

Powercor Australia 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 Powercor Australia'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.<sup>477</sup> This implies that, when proper consideration is given to the characteristics of Powercor Australia's network, Powercor Australia'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'.<sup>478</sup> The model also calculates opex costs as a function of age calibrated against actual data.<sup>479</sup> The modelling conducted by SKM for Powercor Australia is the same as was conducted for ETSA in its recent price review process.<sup>480</sup> 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 more accurate*' compared with the approach originally substituted by PB.<sup>481</sup> 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.<sup>482</sup> The methodology:<sup>483</sup>

*'involves calculating the annual ratio of compounding recommended asset replacement expenditure to the current (undepreciated) replacement cost of the*

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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.

<sup>476</sup> AER, Draft Determination Appendices, Appendix J, pp106-8.

<sup>477</sup> SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p4.

<sup>478</sup> 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 Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), pp8-15.

<sup>479</sup> 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 Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), pp8-15.

<sup>480</sup> 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.

<sup>481</sup> 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.

<sup>482</sup> AER, Draft Determination Appendices, Appendix J, p107.

<sup>483</sup> 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.

*asset base, and then applying 20% of this ratio to calculate the recommended adjustment in the network maintenance forecast opex.'*

Powercor Australia 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 31 per cent of Powercor Australia's opex was strongly linked to age and condition.<sup>484</sup>

Powercor Australia observes that the AER calculated the reduction to Powercor Australia's opex on the basis of the gross customer connections and reliability and quality maintained capex forecasts included in Powercor Australia's Initial Regulatory Proposal, rather than the capex forecasts substituted by the AER in its Draft Determination. Given the significant downward adjustment to Powercor Australia'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,<sup>485</sup> 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.<sup>486</sup> 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.<sup>487</sup>

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 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.<sup>488</sup>

Powercor Australia rejects the 20 per cent factor applied by PB and adopted by the AER.<sup>489</sup> Neither PB nor the AER has provided evidence to support the appropriateness

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<sup>484</sup> 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.

<sup>485</sup> ETSA Utilities, Revised Regulatory Proposal 2010-2015, 14 January 2010 (Attachment 137 to this Revised Regulatory Proposal), pp121-3.

<sup>486</sup> 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.

<sup>487</sup> 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.

<sup>488</sup> 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.

<sup>489</sup> AER, Draft Determination Appendices, Appendix J, p107.

of the factor.<sup>490</sup> PB observed in a footnote in its report supporting the South Australian Draft Determination:<sup>491</sup>

*'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.'*

Powercor Australia 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.<sup>492</sup> Powercor Australia therefore submits that the 20 per cent adjustment made by the AER will not produce a reasonable estimate of the reduction in required opex Powercor Australia 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.<sup>493</sup> Overall, SKM found that only around 31 per cent of Powercor Australia's opex was strongly linked to age and condition.<sup>494</sup> This reduces the potential for replacement capex to reduce Powercor Australia'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 Powercor Australia, acting efficiently and prudently, will require in the next regulatory control period. Acting conservatively, Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

For the reasons outlined above, in this Revised Regulatory Proposal, Powercor Australia 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 outlined in sections 7.5.1 and 7.5.2 above and as reflected in Powercor Australia's Cost Escalation Model.<sup>495</sup>

The resultant opex proposed by Powercor Australia as a result of this proposed scale escalation is set out in Table 7.6 below.

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<sup>490</sup> 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.

<sup>491</sup> 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.

<sup>492</sup> 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.

<sup>493</sup> 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.

<sup>494</sup> 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.

<sup>495</sup> Attachment 9 to this Revised Regulatory Proposal.

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	Cumulative %				
	2011	2012	2013	2014	2015
Network growth	4.43%	6.56%	9.06%	11.71%	1.86%
Customer growth <sup>496</sup>	3.91%	5.89%	7.85%	9.73%	1.94%

**Table 7.5 Scale escalators applied in Powercor Australia's Revised Regulatory Proposal**

	2011	2012	2013	2014	2015	Total
Total scale escalation (\$'000 2010)	1,507	3,648	5,551	7,788	10,227	<b>28,721</b>

**Table 7.6 Opex resulting from Powercor Australia's proposed scale escalation**

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<sup>496</sup> 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, Powercor Australia responds to section 7.5.6 of, and Appendix K to, the AER's Draft Determination regarding Powercor Australia's input (or real) cost escalation and scale escalation. Specifically, this Chapter deals with Powercor Australia'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 Powercor Australia in its Initial Regulatory Proposal.

Powercor Australia does not accept the AER's forecasts of labour costs. In particular, Powercor Australia 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, Powercor Australia 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, Powercor Australia 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, Powercor Australia 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, Powercor Australia 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 Powercor Australia 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, Powercor Australia proposes to also provide the AER with updated materials cost forecasts.

### **8.2 Rule requirements**

Powercor Australia 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 Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia 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.<sup>497</sup>

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.<sup>498</sup> BIS Shrapnel recommended that Powercor Australia use forecast changes to AWOTE in the EGW to escalate its internal labour costs<sup>499</sup> and a simple average of forecast changes to 'construction' and 'property and business services' wages to escalate its outsourced labour costs.<sup>500</sup>

The real labour cost growth and growth in contracts and other costs reflected in Powercor Australia'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:<sup>501</sup>

- 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 Powercor Australia's internal labour costs.

The AER also indicated in its Draft Determination that:<sup>502</sup>

<sup>497</sup> BIS Shrapnel's methodology and findings are set out in the report Wages Outlook for the Electricity Distribution Sector in Victoria, August 2009 (Attachment P0040 to the Initial Regulatory Proposal).

<sup>498</sup> BIS Shrapnel, Wages Outlook for the Electricity Distribution Sector in Victoria, Final Report, August 2009(Attachment P0040 to the Initial Regulatory Proposal), p10.

<sup>499</sup> Powercor Australia notes that it treated the labour costs incurred by CHED Services and PNS as 'internal' labour costs for the purposes of labour cost escalation.

<sup>500</sup> BIS Shrapnel, Wages Outlook for the Electricity Distribution Sector in Victoria, Final Report, August 2009, (Attachment P0040 to the Initial Regulatory Proposal), p1.

<sup>501</sup> AER, Draft Determination Appendix K, pp132-7.

<sup>502</sup> AER, Draft Determination Appendix K, pp132-7.

- 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;
- 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:<sup>503</sup>

- substituted labour cost growth forecasts determined by its consultant, Access Economics; and
- limited the application of Access Economics' EGW measure to 89.6 per cent of Powercor Australia'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.<sup>504</sup> 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.<sup>505</sup>

### **8.3.3 Powercor Australia's response to the Draft Determination**

Powercor Australia 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 Powercor Australia, will have a significant number of assets reaching the end of their economic life over the next

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<sup>503</sup> AER, Draft Determination Appendix K, pp132-7.

<sup>504</sup> AER, Draft Determination Appendix K, pp136-7.

<sup>505</sup> AER, Draft Determination Appendix K, p139.

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:

- 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 Powercor Australia'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 Powercor Australia'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.<sup>506</sup> It measures the average weekly earnings of employed wage and salary earners (excluding those employed in private agriculture).<sup>507</sup> The estimates of the AWE are calculated by dividing estimates of weekly total earnings by estimates of the number of employees.<sup>508</sup>

The AWE provides three earnings measures:

- AWOTE;
- AWTE; and
- average weekly total earnings (i.e. including overtime) of full-time employees.

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<sup>506</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 3 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p22.

<sup>507</sup> ABS, 6301.0 Average Weekly Earnings, February 2010 available at [www.abs.gov.au](http://www.abs.gov.au), accessed 8 July 2010 (Attachment 151 to this Revised Regulatory Proposal).

<sup>508</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 3 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p23.

The LPI is based on a survey sample of approximately 4,800 employers.<sup>509</sup> Employers provide hourly wage and salary costs for a sample of jobs in their workforce.<sup>510</sup> In subsequent quarters, employers provide details of payments made to the current occupants of these same jobs.<sup>511</sup>

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.<sup>512</sup> 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.<sup>513</sup>

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 Shrapnel'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:<sup>514</sup>

*'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

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<sup>509</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p23.

<sup>510</sup> ABS, 6345.0 Labour Price Index, March 2010 available at [www.abs.gov.au](http://www.abs.gov.au), accessed 17 July 2010 (Attachment 144 to this Revised Regulatory Proposal).

<sup>511</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower (Attachment 143 to this Revised Regulatory Proposal), 13 July 2010, p24.

<sup>512</sup> AER, Draft Determination Appendix K, p132.

<sup>513</sup> Access Economics, Forecast growth in labour costs: March 2010 report, 16 March 2010, pp112-3.

<sup>514</sup> BIS Shrapnel, *Wages Outlook for the Electricity Distribution Sector in Victoria, Final Report*, August 2009, included as Attachment P0040 to the Initial Regulatory Proposal, p10.



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.<sup>515</sup> 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.<sup>516</sup>

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.

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:<sup>517</sup>

*'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.<sup>518</sup>

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:<sup>519</sup>

- 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).<sup>520</sup> 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.<sup>521</sup> This is because, during the recent economic downturn there

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<sup>515</sup> Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, pp113-4.

<sup>516</sup> Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, p114.

<sup>517</sup> Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, p11.

<sup>518</sup> KPMG, *Labour Cost Forecasts for Powercor and CitiPower*, 13 July 2010, (Attachment 143 to this Revised Regulatory Proposal), p22-27.

<sup>519</sup> KPMG, *Labour Cost Forecasts for Powercor and CitiPower*, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p28.

<sup>520</sup> KPMG, *Labour Cost Forecasts for Powercor and CitiPower*, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), pp28-30.

<sup>521</sup> KPMG, *Labour Cost Forecasts for Powercor and CitiPower*, 13 July 2010 ( Attachment 143 to this Revised Regulatory Proposal), p30.



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.<sup>522</sup>

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.<sup>523</sup> KPMG observes that:<sup>524</sup>

*'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, Powercor Australia 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.<sup>525</sup>

Powercor Australia 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 Powercor Australia's labour and contract and other costs escalators proposed in this Revised Regulatory Proposal are based do take into account productivity improvements. Accordingly, Powercor Australia'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 Powercor Australia'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,<sup>526</sup> currency of data is not a reason for rejecting a DNSP's proposed methodology for determining input cost escalators.

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<sup>522</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p30.

<sup>523</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p30.

<sup>524</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p31.

<sup>525</sup> AER, Draft Determination Appendix K, p133.

<sup>526</sup> AER, Draft Determination Appendix K, pp136-7.

To address the AER's concerns regarding the currency of Powercor Australia's labour cost escalators, Powercor Australia 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, Powercor Australia will provide the updated forecasts to the AER by 13 September 2010.

### **8.3.3.2 Labour costs escalators (for internal labour)**

Powercor Australia submits that it is not reasonable to use the growth rates determined by Access Economics. Rather, Powercor Australia 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, Powercor Australia's has used labour cost escalators based on KPMG's EGW forecasts. Powercor Australia 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, Powercor Australia submits that:

- contrary to the AER's position, it is appropriate to take into account Powercor Australia's EBA rates for 2010; and
- contrary to the AER's position, it is reasonable to apply the growth in the EGW labour rate to 100 per cent of Powercor Australia'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<sup>527</sup>, 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

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<sup>527</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010, (Attachment 143 to this Revised Regulatory Proposal),.

industry LPI data series.<sup>528</sup> 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.<sup>529</sup> 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.

*Powercor Australia's proposed labour costs escalators*

For the purposes of preparing this Revised Regulatory Proposal, Powercor Australia engaged KPMG to forecast growth in labour costs for the next regulatory control period. Powercor Australia considers that KPMG's EGW forecasts constitute a 'realistic expectation' of labour costs in the 2011-15 period and, accordingly, that Powercor Australia's revised escalators, based on KPMG's EGW forecasts, produce total capex and opex forecasts that reasonably reflect the capex criteria and opex criteria.

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<sup>528</sup> 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.

<sup>529</sup> 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.

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Consistent with the discussion earlier in this Chapter, the AER should accept Powercor Australia's labour costs escalators because they:

- are based on AWE measures, rather than the LPI; and
- take into account anticipated increases in productivity.

Powercor Australia 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.<sup>530</sup> Forecasts produced by LCM were relied on by the AER in decisions as set out in Table 8.2 below.

AER decision	Use of KPMG's LCM forecasts by AER
AER, SP AusNet Draft Transmission Determination	AER used Econtech's <sup>531</sup> forecasts to conclude that the forecasts provided by SP AusNet (prepared by BIS Shrapnel) were ' <i>not excessive</i> '. <sup>532</sup>  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. <sup>533</sup>
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 ' <i>sufficiently robust... to rely on ... in assessing the reasonableness of SP AusNet's proposal.</i> ' <sup>534</sup>
AER, NSW Draft Determination	The AER was satisfied that Econtech's forecasts were robust and applied these. <sup>535</sup>
AER, NSW Final Determination	The AER adopted updated Econtech forecasts. <sup>536</sup> The AER considered that Econtech's methodology was robust and transparent. <sup>537</sup>

**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, Powercor Australia notes that, contrary to the concerns expressed by

<sup>530</sup> 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.

<sup>531</sup> Econtech Pty Ltd merged with KPMG in August 2008: AER, NSW Draft Determination (Attachment 142 to this Revised Regulatory Proposal), p534, footnote 1238.

<sup>532</sup> AER, Draft Decision, SP AusNet Transmission Determination 2008-09 to 2013-14, 31 August 2007 (Attachment 147 to this Revised Regulatory Proposal), p141.

<sup>533</sup> 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.

<sup>534</sup> AER, Final Decision, SP AusNet Transmission Determination 2008-09 to 2013-14, 14 January 2008 (Attachment 148 to this Revised Regulatory Proposal), p116.

<sup>535</sup> AER, NSW Draft Determination (Attachment 142 to this Revised Regulatory Proposal), p538.

<sup>536</sup> AER, NSW Final Determination (Attachment 141 to this Revised Regulatory Proposal), pp495-6.

<sup>537</sup> AER, NSW Final Determination (Attachment 141 to this Revised Regulatory Proposal), pp491-2.

the AER in the Draft Determination,<sup>538</sup> its escalators in the Initial Regulatory Proposal did not represent a moving average. Rather, Powercor Australia took a simple average of labour growth forecasts for two financial years to calculate the nominal escalator for a calendar year (e.g. Powercor Australia 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.

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.*'<sup>539</sup> 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, Powercor Australia's current EBA rates were negotiated at a time when the ESCV's efficiency carry over mechanism provided incentives for Powercor Australia 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.<sup>540</sup>

*Application of labour cost escalators*

The AER rejected BIS Shrapnel's application of EGW rates to internal labour cost forecasts.<sup>541</sup> 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.<sup>542</sup>

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.<sup>543</sup> The AER then applied these estimated weightings to the EGW and general Victorian wage growth

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<sup>538</sup> AER, Draft Determination, p128.

<sup>539</sup> AER, Draft Determination Appendix K, p136.

<sup>540</sup> AER, South Australian Final Determination (Attachment 22 to this Revised Regulatory Proposal), p96.

<sup>541</sup> AER, Draft Determination Appendix K, pp133-4.

<sup>542</sup> AER, Draft Determination Appendix K, pp134-5.

<sup>543</sup> AER, Draft Determination Appendix K, p135.



forecasts prepared by Access Economics to determine a weighted average labour cost growth forecast.<sup>544</sup>

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.<sup>545</sup> 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.<sup>546</sup>

Accordingly, as noted by KPMG, if the composition of Powercor Australia's internal workforce (including employees seconded to CHED Services and PNS) is similar to the average for the industry, changes in internal labour costs would be adequately reflected in EGW measures.<sup>547</sup>

Powercor Australia 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, Powercor Australia 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 Powercor Australia 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.

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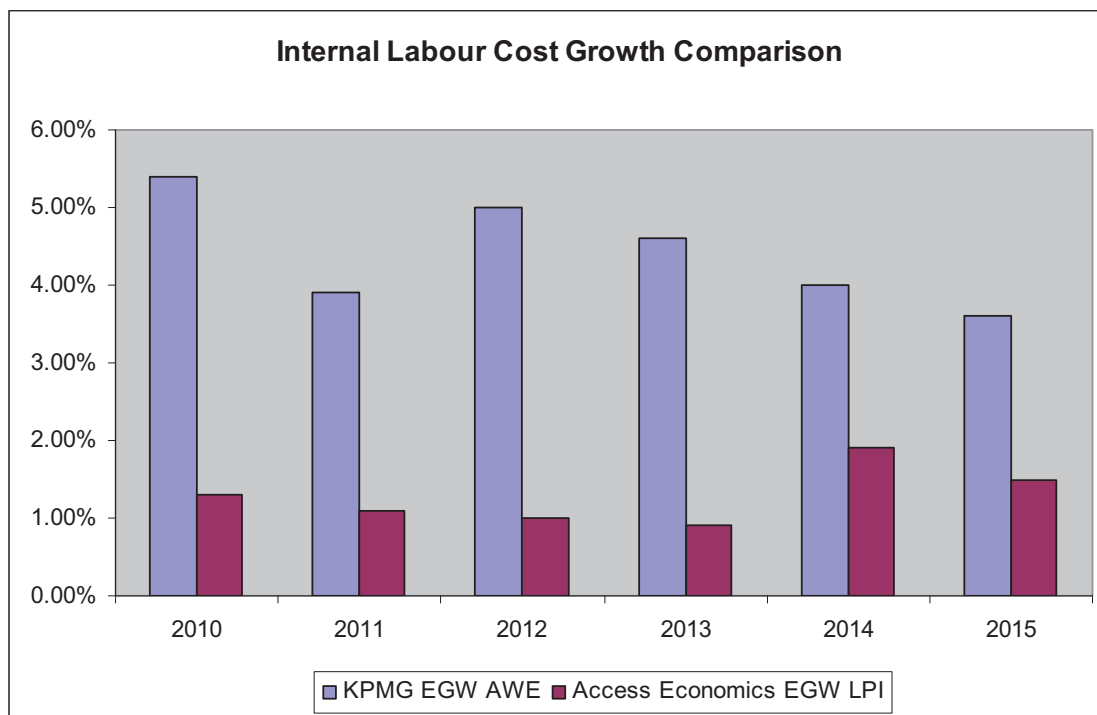
<sup>544</sup> AER, Draft Determination Appendix K, p135.

<sup>545</sup> AER, Draft Determination Appendix K, p134.

<sup>546</sup> 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).

<sup>547</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p33.





**Figure 8.1 Graph comparing KPMG's labour cost forecast to Access Economics' labour cost forecast**

*Powercor Australia's proposed contract and other cost escalators*

The contract and other costs escalators proposed by Powercor Australia in this Revised Regulatory Proposal are based on KPMG's forecasts. Powercor Australia considers these escalators reflect a realistic expectation of the external labour costs that will be incurred by Powercor Australia 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.

Powercor Australia 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.<sup>548</sup> However, the 'property and business services' classification has since been split into three separate industry classifications:<sup>549</sup>

- 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

<sup>548</sup> AER, Draft Determination Appendix K, p136.

<sup>549</sup> 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).

purposes of the outsourced labour costs.<sup>550</sup> In calculating its contract and other costs escalators, Powercor Australia has taken the simple average of each of the measures forecast by KPMG.

## **8.4 Materials escalators**

### **8.4.1 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia adopted materials escalators as determined by independent engineering consultants SKM.<sup>551</sup>

### **8.4.2 AER's Draft Determination**

The AER made a number of adjustments to the materials escalators proposed by Powercor Australia.<sup>552</sup>

### **8.4.3 Powercor Australia's response to the Draft Determination**

Since its Initial Regulatory Proposal, in July 2010 SKM provided Powercor Australia 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.<sup>553</sup>

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.<sup>554</sup>

In updating the materials escalators, SKM incorporated the following changes having regard to the AER's Draft Determination:<sup>555</sup>

- 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.

Powercor Australia 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, Powercor Australia 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 Powercor Australia will provide the updated forecasts to the AER by 13 September 2010.

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<sup>550</sup> KPMG, Labour Cost Forecasts for Powercor and CitiPower, 13 July 2010 (Attachment 143 to this Revised Regulatory Proposal), p33.

<sup>551</sup> SKM's methodology and findings are set out in the report Victorian Distribution Network Service Providers annual material cost escalators 2010-15(Attachment P0041 to the Initial Regulatory Proposal).

<sup>552</sup> AER, Draft Determination Appendix K, pp118-125, 139-145.

<sup>553</sup> 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.

<sup>554</sup> 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.

<sup>555</sup> 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.

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## 8.5 Powercor Australia's Revised Regulatory Proposal

For the reasons outlined above, in this Revised Regulatory Proposal, Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

	% (real)					
	2010	2011	2012	2013	2014	2015
Network	9.37	6.06	-0.17	-0.45	-1.10	-1.06
SCADA/network control	1.97	0.18	0.43	-0.05	-0.07	-0.08
Non network general IT	1.96	0.18	0.42	-0.07	-0.07	-0.07
Non network general other	1.76	0.16	0.37	-0.06	-0.06	-0.06
Weighted average	8.72	5.56	-0.14	-0.42	-1.01	-0.97

**Table 8.4 Materials cost escalators reflected in Powercor Australia's Revised Regulatory Proposal**

Table 8.5 below shows net capex due to labour cost escalation.

	\$,000 (\$2010)					
	2010	2011	2012	2013	2014	2015
Labour escalation	4,221	8,085	12,227	15,500	18,748	22,166
Material escalation	5,241	10,613	11,248	11,110	10,053	9,543
Contract & other cost escalation	4,421	9,294	12,934	15,232	17,201	18,596

**Table 8.5 Net capex due to real cost escalation**

Table 8.6 shows opex due to labour cost escalation.

	\$,000 (\$2010)					
	2010	2011	2012	2013	2014	2015
Labour escalation	0	2,276	5,393	8,189	10,503	12,685
Material escalation	0	276	218	161	80	(3)
Contract & other cost escalation	0	1,402	2,950	3,868	4,594	5,458

**Table 8.6 Opex due to real cost escalation**

## **9. FORECAST CAPITAL EXPENDITURE**

In this Chapter of the Revised Regulatory Proposal, Powercor Australia responds to Chapter 8 of the AER's Draft Determination regarding Powercor Australia'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**

Powercor Australia does not accept the AER's rejection of its proposed capex forecasts for the next regulatory control period. Powercor Australia submits that the AER's downward adjustment of almost \$580 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 Powercor Australia'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 Powercor Australia's proposal for a number of capex categories. Specifically, Powercor Australia 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 Powercor Australia'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 Powercor Australia's historical forecasting accuracy is poor.

#### **9.1.2 New customer connections capex**

Powercor Australia 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.<sup>556</sup>

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

### **9.1.3 Reinforcement capex**

Powercor Australia 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:

- Powercor Australia's internal planning criteria incorporate the same criteria as Powercor Australia's governance documents, which Nuttall Consulting concluded would be expected to deliver prudent and efficient outcomes;
- Powercor Australia's processes take into account synergies and result in forecasts that are economically justified;
- overall, SKM found that Powercor Australia'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 lower than the maximum demand forecasts reconciled with NIEIR's system maximum demand forecast (presented in Chapter 4) and thus the maximum demand forecasts used to forecast reinforcement capex are conservative and not likely to result in a systematic upward bias in the estimate.

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

Powercor Australia contends that each of the reinforcement projects in the Revised Regulatory Proposal will be required as proposed in the next regulatory control period.

### **9.1.4 Reliability and quality maintained capex**

Powercor Australia 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, Powercor Australia has adopted the AER's forecasts for its overhead and underground line replacement and HV and LV switch replacement programs.

Powercor Australia has provided in this Revised Regulatory Proposal additional details regarding key reliability and quality maintained capex programs for the next regulatory control period.

Powercor Australia 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 Powercor Australia's forecasts. Removing the two major drivers of the increase in Powercor

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<sup>556</sup> AER, Final Customer Contributions Decision.

Australia's forecast in the next regulatory control period (the conductor replacement and reliability programs), which PB considered should be evaluated as step change increases, PB concluded that the variation between the calibrated Repex Model and Powercor Australia's forecasts did not justify an adjustment to Powercor Australia's proposed forecast.

#### **9.1.5 Environmental, safety and legal capex**

Powercor Australia does not contest the AER's Draft Determination with respect to environmental, safety and legal capex. However, Powercor Australia 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**

While the AER found that Victorian DNSPs have underspent in relation to the ESCV's benchmark allowance for the current regulatory control period, this is not the case for Powercor Australia. Based on the AER's analysis, Powercor Australia only underspent (relative to the ESCV allowance) by around 8.5 per cent.

The AER has not considered the circumstances of Powercor Australia's network in assessing its proposed SCADA and network control capex. Powercor Australia 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**

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

Powercor Australia'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. Powercor Australia does not consider that an event, such as the AMI roll-out, will occur in the next regulatory control period such that Powercor Australia's non-network – IT capex should be constrained to the levels of its actual expenditure in the current regulatory control period. Powercor Australia 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 Powercor Australia 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, Powercor Australia 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. Powercor Australia rejects the AER's proposition that reinforcement capex deferrals would contribute to the funding of AMI leveraged projects.

Powercor Australia does not consider that the non-network – other capex included in the AER's Draft Determination, an amount significantly less than historical capex, reasonably reflects the capex criteria.



## **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.

Powercor Australia 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, Powercor Australia considers that there may be a range of forecasts that reasonably reflect the capex criteria.<sup>557</sup> Powercor Australia 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 Powercor Australia'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 Powercor Australia 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 Powercor Australia 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 Powercor Australia'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

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<sup>557</sup> 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.

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capex reasonably reflect the capex criteria, the expenditure should be allowed by the AER.

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.<sup>558</sup>

### 9.3 Powercor Australia's Initial Regulatory Proposal

Powercor Australia'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 Powercor Australia's Initial Regulatory Proposal is discussed in further detail below, by capex category.

Gross expenditure category	\$'000s (real 2010)					
	2011	2012	2013	2014	2015	Total
Reinforcements	53,443	55,856	62,604	68,805	70,577	311,285
New Customer Connections	154,676	160,053	163,359	168,827	174,460	821,375
<b>Total demand related</b>	<b>208,119</b>	<b>215,909</b>	<b>225,963</b>	<b>237,632</b>	<b>245,037</b>	<b>1,132,660</b>
Reliability and Quality Maintained	87,428	89,526	94,428	95,203	97,493	464,078
Environmental, Safety and Legal	15,037	10,789	12,361	11,695	10,656	60,538
SCADA and Network Control	6,801	7,381	7,582	7,471	7,467	36,702
<b>Total non-demand related</b>	<b>109,266</b>	<b>107,696</b>	<b>114,371</b>	<b>114,369</b>	<b>115,616</b>	<b>561,318</b>
<b>Demand and non-demand related</b>	<b>317,385</b>	<b>323,605</b>	<b>340,334</b>	<b>352,001</b>	<b>360,653</b>	<b>1,693,978</b>
Non-network	41,968	39,270	38,180	47,096	40,713	207,227
Less Customer Contributions	(58,871)	(60,905)	(62,447)	(64,637)	(66,832)	(313,692)
<b>Net capex</b>	<b>300,482</b>	<b>301,970</b>	<b>316,067</b>	<b>334,460</b>	<b>334,534</b>	<b>1,587,513</b>

Table 9.1 Powercor Australia'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 Powercor Australia'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:

<sup>558</sup> 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 Powercor Australia's Initial Regulatory Proposal, except for the residential subdivisions and HV connections forecasts, for which the AER substituted average expenditure from 2006-09;
- reinforcement capex as forecast by Nuttall Consulting using the weighted average probability (derived from six project reviews and Nuttall Consulting's 'broader findings' in respect of Powercor Australia's forecasting methodology);
- 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 based on constant expenditure of \$8m per annum.

The basis for the AER's Draft Determination, and Powercor Australia'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**

Powercor Australia 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). Powercor Australia notes, however, that the AER should incorporate 2009 actual data in its consideration of these capex categories in the Final Determination.

Powercor Australia also does not contest the AER's Draft Determination with respect to equity raising costs.<sup>559</sup>

Powercor Australia 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 Powercor Australia 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 Powercor Australia's proposal for a number of capex categories. Specifically, Powercor Australia is concerned with the following:

- 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;

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<sup>559</sup> AER, Draft Determination, p439; AER, Draft Determination, Appendix N.

- 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 Powercor Australia'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 Powercor Australia'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**

Powercor Australia 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.

Powercor Australia 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 Powercor Australia'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 Powercor Australia 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.<sup>560</sup> The Court stated:<sup>561</sup>

*'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 aside on this ground pursuant to s 5(1)(f) of the ADJR Act and s39B of the Judicial Act.'*

Powercor Australia 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, Powercor Australia notes that, as a practical matter, by seeking particular evidentiary material to achieve the necessary satisfaction under the Rules, the AER is

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<sup>560</sup> *Telstra v Australian Competition Tribunal* (2009) 175 FCR 201 at [174]-[175].

<sup>561</sup> *Telstra v Australian Competition Tribunal* (2009) 175 FCR 201 at [171], [173]-[175].



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 of law.<sup>562</sup>

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.<sup>563</sup>

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*'<sup>564</sup> 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 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.

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<sup>562</sup> For example, the AER appears to have done this in respect of the AMI leveraged projects proposed by Powercor Australia as part of non-network – IT capex: AER, Draft Determination, p423.

<sup>563</sup> *Telstra v Australian Competition Tribunal* (2009) 175 FCR 201 at [173]-[175].

<sup>564</sup> For example, see AER, Draft Determination, p403.



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.<sup>565</sup>

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 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). Powercor Australia notes that using data from 2004-08 or 2006-08 results in a systematic

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<sup>565</sup> The AER indicated in respect of Powercor Australia'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 Powercor Australia did not link its capex proposals to any risk assessment in support of the overall works program: AER, Draft Determination, pp401-2. Similarly, in respect of Powercor Australia's proposed replacement of mobile cranes, the AER noted that *a risk management approach to compliance allows businesses to assess their obligations and bear compliance risk where they are willing to do so.*: AER, Draft Determination, p431.

downward bias in the trend in Powercor Australia'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.'*<sup>566</sup> On 30 April 2010, Powercor Australia 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.<sup>567</sup> 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.

Powercor Australia 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<sup>568</sup> but did not consider these unaudited costs for the purposes of assessing Powercor Australia's proposed capex. Powercor Australia 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 Powercor Australia's capex forecasts, Powercor Australia 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 Powercor Australia's proposed capex and forecasting substitute capex. The AER outlined its approach to the review of the Victorian distributors' forecast capex as follows:<sup>569</sup>

*'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 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 Powercor Australia's forecasts of non-network capex did not

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<sup>566</sup> AER, Draft Determination, pp400, 410, 419 and 429.

<sup>567</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p23.

<sup>568</sup> AER, Draft Determination, p238.

<sup>569</sup> AER, Draft Determination, p288.

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 Powercor Australia's proposed reliability and quality maintained capex.

With the exception of customer connections capex (in respect of which, as discussed further below, Powercor Australia 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'.<sup>570</sup>

As noted in Powercor Australia's Initial Regulatory Proposal,<sup>571</sup> 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:<sup>572</sup>

*'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.'*

Powercor Australia 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). Powercor Australia 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, Powercor Australia 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.

#### **9.6.5 Adjustments to Powercor Australia's forecasts**

As noted above, clause 6.12.3(f) of the Rules provides that the AER is only permitted to amend Powercor Australia'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

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<sup>570</sup> AER Draft Determination, pp399, 409, 419 and 429.

<sup>571</sup> Initial Regulatory Proposal, pp139-40.

<sup>572</sup> ESCV's 2006-10 EDPR, p269.

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, Powercor Australia submits that the AER must adjust the forecasts included in Powercor Australia'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, Powercor Australia requested (by email) copies of the curriculum vitae of each of the authors of the Nuttall Consulting report. Powercor Australia 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 Powercor Australia'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 Powercor Australia's forecasts**

In its Draft Determination, the AER had regard to the past forecasting performance of Victorian DNSPs.<sup>573</sup> The AER concluded that DNSPs' capex forecasts tend to systematically over estimate actual capex.<sup>574</sup>

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.

Despite this, in the current regulatory control period, Powercor Australia's actual capex in 2006-09 **exceeded** the benchmark set by the ESCV and is expected to exceed the benchmark for 2010 (see Table 9.2 below). The difference is largely attributable to non-routine new customer connections, which have increased significantly due to stronger growth in customer numbers and steady growth in reinforcement expenditure. This was discussed further in sections 5.5 and 5.10 of the Initial Regulatory Proposal.

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<sup>573</sup> AER, Draft Determination, pp291-2, 315, 356-7, 409, 418 and 428. The AER indicated that it considered Powercor Australia'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.

<sup>574</sup> AER, Draft Determination, pp291-2.

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	\$'000 2010					
Capex	2006	2007	2008	2009	2010	Total
Actual/projected	223,199	253,153	242,619	230,007	263,991	1,212,969
Regulatory allowance	203,891	220,924	225,848	222,641	225,806	1,099,111
<b>Difference</b>	<b>19,307</b>	<b>32,230</b>	<b>16,771</b>	<b>7,365</b>	<b>38,185</b>	<b>113,858</b>

**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,<sup>575</sup> as shown in Table 9.2 above, Powercor Australia's 2009 actual capex was consistent with its 2009 forecasts.

## **9.7 New customer connections capex**

### **9.7.1 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia included, in the total forecast capex, new customer connections capex net of customer contributions.

#### **9.7.1.1 Gross customer connections**

Powercor Australia 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 Powercor Australia was outlined in the Initial Regulatory Proposal.<sup>576</sup>

Powercor Australia 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**

Powercor Australia 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.<sup>577</sup>

After lodging its Initial Regulatory Proposal, Powercor Australia raised concerns with the AER that, in forecasting capital contributions, Powercor Australia had used the 2009 Contribution Rate and had only adjusted the 2009 Contribution Rate to account for expected changes to the MCR.<sup>578</sup> The Contribution Rate is also a function of three other factors: the P<sub>0</sub>, 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.

<sup>575</sup> AER, Draft Determination, p292.

<sup>576</sup> Initial Regulatory Proposal, pp88-91.

<sup>577</sup> Initial Regulatory Proposal, p87.

<sup>578</sup> Letter to Mr Blair Burkitt, Director Network Regulation South, AER, 19 April 2010, pp5-7.



Powercor Australia indicated to the AER that it would propose revised customer contribution forecasts in its Revised Regulatory Proposal that are consistent with:<sup>579</sup>

- 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;<sup>580</sup> and
- the proposed P<sub>0</sub>, 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 accepted Powercor Australia's proposed gross customer connections forecast in respect of function code 118 (cogeneration).<sup>581</sup>

The AER rejected the remaining gross customer connections forecasts put forward by Powercor Australia because:<sup>582</sup>

- Powercor Australia 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 Powercor Australia's proposed classification of a number of services as standard control.

Regarding the classification of services, the Draft Determination referred to Powercor Australia including in its proposed customer connections forecasts capex relating to services the AER identified as '*labour and materials for routine connections*'.<sup>583</sup> Powercor Australia has assumed the AER is referring to capex in function codes 114 and 115.

Powercor Australia'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.

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<sup>579</sup> Letter to Mr Blair Burkitt, Director Network Regulation South, AER, 19 April 2010, p8.

<sup>580</sup> The AER's decision regarding CitiPower's customer contribution charges applies equally to Powercor Australia because the DNSPs adopt the same methodology for determining customer contribution charges.

<sup>581</sup> AER, spreadsheet titled 'Draft Decision – Master Capex – Powercor'.

<sup>582</sup> AER, Draft Determination, pp306-7.

<sup>583</sup> AER, Draft Determination, p307.



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 than 500kVA.<sup>584</sup>

#### **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.<sup>585</sup>

#### **9.7.3 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia 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.

Powercor Australia attaches to this Revised Regulatory Proposal its Customer Capex Model and Customer Contributions Rate Model, which give effect to the above.<sup>586</sup>

Powercor Australia 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, Powercor Australia has revised its gross customer connections forecasts for the next regulatory control period.

Given the AER's acceptance of Powercor Australia's forecasts for connections under function code 118 (cogeneration), Powercor Australia retained the forecasts included in its Initial Regulatory Proposal.

For all function codes except function code 118, Powercor Australia 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, Powercor Australia has assumed that the 2010-15 annual volume of projects will be equal to the average 2006-09 annual volume of projects.

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 Powercor Australia's customer connections capex forecasts because they are based on historic expenditure from more than one year (i.e. 2006-09).

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<sup>584</sup> AER, Draft Determination, p307.

<sup>585</sup> AER, Draft Determination, pp305-308.

<sup>586</sup> Customer Capex Model (Attachment 7 to this Revised Regulatory Proposal) and Customer Contributions Rate Model (Attachment 8 to this Revised Regulatory Proposal).

### **9.7.3.2 Function codes 114 and 115**

In an email to the AER of 22 February 2010, Powercor Australia 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.

Powercor Australia considers that the AER has made an error in removing function codes 114 and 115 from standard control and allocating them to alternative control. Powercor Australia 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;
- Powercor Australia'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'*.<sup>587</sup> The AER has thus confirmed the allocation of costs in respect of routine connections as signed off by Deloitte is appropriate; and
- Powercor Australia's approved CAM classifies these costs as standard control.

Powercor Australia 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 Powercor Australia'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 Powercor Australia to provide volumes for these function codes. For

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<sup>587</sup> AER, Draft Determination, p23.

the purposes of forecasting costs in function codes 114 and 115, Powercor Australia 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 Powercor Australia'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, Powercor Australia 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. Powercor Australia 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.
- 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, Powercor Australia 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, Powercor Australia has attached to this Revised Regulatory Proposal its Customer Contribution Rate and Customer Capex Models, which the AER can use for this purpose.<sup>588</sup>

### **9.7.4 Powercor Australia's Revised Regulatory Proposal**

The new customer connections capex forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 9.3 below.

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<sup>588</sup> Attachments 7 and 8 to this Revised Regulatory Proposal.

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Expenditure category	\$'000 (real 2010)					
	2011	2012	2013	2014	2015	Total
Gross new customer connections	141,298	144,460	147,090	148,956	150,651	<b>732,456</b>
Customer contribution	(42,190)	(43,248)	(44,062)	(44,582)	(45,124)	<b>(219,205)</b>
<b>Net new customer connections</b>	<b>99,109</b>	<b>101,212</b>	<b>103,028</b>	<b>104,375</b>	<b>105,527</b>	<b>513,251</b>

Table 9.3 Forecast customer capex included in Powercor Australia's Revised Regulatory Proposal

## 9.8 Reinforcement capex

### 9.8.1 Powercor Australia's Initial Regulatory Proposal

Reinforcement capex relates to capital works that are required to augment Powercor Australia'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 Powercor Australia 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, Powercor Australia's reinforcement capex is therefore driven by maximum demand forecasts and the resultant energy at risk. For low voltage and high 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.<sup>589</sup>

Subsequent to the Initial Regulatory Proposal, Powercor Australia provided to the AER (among other things) energy at risk calculations for each sub-transmission and zone substation.<sup>590</sup>

### 9.8.2 AER's Draft Determination

The AER rejected Powercor Australia's methodology for forecasting reinforcement capex on the basis that the process adopted by Powercor Australia for a bottom-up build of reinforcement capex does not provide a reasonable unbiased estimate of efficient future reinforcement capex.<sup>591</sup>

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 Powercor Australia results in a systematic upward bias in the resultant estimate

<sup>589</sup> Initial Regulatory Proposal, pp79-83 and 401-16.

<sup>590</sup> The calculations were provided to the AER on CD on 27 January 2010.

<sup>591</sup> AER, Draft Determination, pp334-7.

of future reinforcement capex.<sup>592</sup> Specifically, Nuttall Consulting concluded that Powercor Australia'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;<sup>593</sup> 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.<sup>594</sup>
- Powercor Australia's use of a load profile from 2009 will result in a systematic upward bias in its estimates of future prudent and efficient reinforcement capex.<sup>595</sup> This is because the extended periods of hot weather in 2008-09 mean the 2009 load profile is relatively flat.<sup>596</sup>
- Powercor Australia'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.<sup>597</sup>

The AER also concluded that:

- Powercor Australia'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.<sup>598</sup>
- Powercor Australia'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 of factors in addition to the cost of energy at risk and was heavily reliant on the judgement of planning engineers.<sup>599</sup>

Finally, based on Nuttall Consulting's assessment, the AER was not satisfied as to the likelihood of Powercor Australia's expenditure being required as proposed in the next regulatory control period.<sup>600</sup> Nuttall Consulting concluded that there was a moderate probability (62 per cent) of Powercor Australia's reinforcement capex being required as proposed.<sup>601</sup>

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<sup>592</sup> AER, Draft Determination, p324.

<sup>593</sup> AER, Draft Determination, p319.

<sup>594</sup> AER, Draft Determination, p322.

<sup>595</sup> AER, Draft Determination, p324.

<sup>596</sup> AER, Draft Determination, p324.

<sup>597</sup> AER, Draft Determination, p318.

<sup>598</sup> AER, Draft Determination, p322.

<sup>599</sup> AER, Draft Determination, p335.

<sup>600</sup> AER, Draft Determination, p324. The AER accepted Nuttall Consulting's findings in reaching its conclusions on Powercor Australia's proposed reinforcement capex: AER, Draft Determination, p336.

<sup>601</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p181. Powercor Australia assumes that Nuttall Consulting's reference to the CBD Security of Supply and Metro 2012 projects in its report is a typographical error.

In place of Powercor Australia's reinforcement capex forecasts, the AER substituted forecasts prepared by Nuttall Consulting.<sup>602</sup> To determine reinforcement capex for the next regulatory control period Nuttall Consulting:<sup>603</sup>

- reviewed six of the projects proposed by Powercor Australia 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 individual 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 Powercor Australia's proposed total reinforcement capex; and
- 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.

Following this process, Nuttall Consulting recommended reducing Powercor Australia's forecast of reinforcement capex by 38 per cent.<sup>604</sup>

### **9.8.3 Powercor Australia's response to the AER's Draft Determination**

#### **9.8.3.1 Summary**

Powercor Australia 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:
  - Powercor Australia's internal planning criteria incorporate the same criteria as Powercor Australia's governance documents, which Nuttall Consulting concluded would be expected to deliver prudent and efficient outcomes;
  - Powercor Australia's processes take into account synergies and result in forecasts that are economically justified; and
  - overall, SKM found that Powercor Australia's energy at risk modelling (including its load duration and transformer outage rate assumptions) is likely to **understate** energy at risk;<sup>605</sup> and
- the zone substation level maximum demand forecasts used to prepare the reinforcement capex forecasts are lower than the maximum demand forecasts reconciled with NIEIR's system maximum demand forecast (presented in Chapter 4). Thus the maximum demand forecasts used to forecast reinforcement

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<sup>602</sup> AER, Draft Determination, p336.

<sup>603</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp55-6.

<sup>604</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p181; AER, Draft Determination, p336.

<sup>605</sup> SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p21.



capex are conservative and not likely to result in a systematic upward bias in the estimate.

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

Powercor Australia 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 Powercor Australia's proposed reinforcement projects are set out below and are included in material project templates.<sup>606</sup>

### **9.8.3.2 Powercor Australia's methodology for forecasting reinforcement capex**

Powercor Australia'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 Powercor Australia'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.*'<sup>607</sup> Powercor Australia's internal planning criteria incorporate the same criteria as Powercor Australia's governance documents. The rigour of the analysis applied by Powercor Australia 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*

Powercor Australia takes synergies into account when developing its forecasts of reinforcement capex. For example, Powercor Australia notes that synergies are reflected in its Transformer and Distribution Circuit Breaker Strategic Replacement Program<sup>608</sup>. In addition, the asset management plan in respect of zone substation transformers makes it clear that '*[t]he suggested replacement program may have to be adjusted to suit any unexpected load changes.*'<sup>609</sup>

Nuttall Consulting recognised that, in some circumstances, projects may be advanced or their scopes increased as they move through DNSPs' capital governance processes.<sup>610</sup> Nuttall Consulting concluded, however, that this will most likely result in overall expenditure being less than the simple summation of the project plans.<sup>611</sup> Powercor Australia maintains that project scopes and timing move in both directions as projects move through Powercor Australia's governance processes. As noted above, this reflects changes in relevant circumstances, rather than the application of a more detailed analysis.

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<sup>606</sup> Included in Attachment 161 to this Revised Regulatory Proposal.

<sup>607</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p101; AER, Draft Determination, p303.

<sup>608</sup> Attachment P0106 to the Initial Regulatory Proposal

<sup>609</sup> Powercor Australia, Zone Substation Transformers Asset Management Plan, November 2009 (Attachment P0104 to the Initial Regulatory Proposal), p28.

<sup>610</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp51-2.

<sup>611</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p51.

*Cost benefit analyses*

To assist the AER with its assessment of Powercor Australia's proposed reinforcement capex, Powercor Australia has conducted cost benefit analyses in respect of five of the major projects reviewed by Nuttall Consulting. 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 these projects are economically justified. Powercor Australia notes that it has not provided a material project template with this Revised Regulatory Proposal in respect of the Eagle Hawk zone substation upgrade because Nuttall Consulting's concern was in respect of the load profile assumptions underpinning the forecast.<sup>612</sup> This issue is addressed further below.

Powercor Australia submits that the cost benefit analyses conducted for these major projects demonstrates that Powercor Australia'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*

Powercor Australia's use of a load profile from 2009 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 Powercor Australia 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.<sup>613</sup>

Powercor Australia'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.<sup>614</sup> In addition, the independent expert, SKM, concluded that Powercor Australia's transformer outage duration assumptions are in line with international experience.<sup>615</sup>

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

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<sup>612</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p178.

<sup>613</sup> SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p19.

<sup>614</sup> 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.

<sup>615</sup> SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p16.

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would be ordered and manufactured. There are very long lead times in procuring transformers (up to 18 months).<sup>616</sup>

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 Powercor Australia'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 Powercor Australia to pursue at this time. Nuttall Consulting concluded that Powercor Australia is relatively efficient.<sup>617</sup> It follows that, if it was efficient to hold spares or to seek to negotiate special terms with manufacturers, Powercor Australia would already be doing this.

There are significant costs associated with implementation of the measures for reducing outage durations proposed by Nuttall Consulting. Powercor Australia notes there are 11 'families' or 'generic types' of power transformers currently in service on its network (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.

Voltage (kV)	Vector Group	Size (MVA)	Cooling Bank
66/11	DY1	20/33	Attached
66/22	11YY0	20/27	Attached
66/22	YY	20/33	Attached
66/22	YY	20/33	Separate
66/22	YZ	10/13.5	Attached
66/22	DY1	10/13.5	Attached
66/22	DY1	20/33	Attached
66/22	DY1	20/33	Separate
66/22	DYN1	10/13.5	Attached
66/22	DYN1	20/33	Attached
66/22	31DY9	10/13.5	Attached

**Table 9.4 Powercor Australia's power transformer generic types**

Given the above range of transformers, it would be not be efficient for Powercor Australia to seek to hold spares of each. Powercor Australia notes that while it is seeking to reduce outage durations by improving the interchangeability of transformers between sites through standardisation,<sup>618</sup> 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 Powercor Australia's network. Powercor Australia would then have to negotiate a holding or leasing arrangement for

<sup>616</sup> Powercor Australia, Zone Substation Transformers Asset Management Plan, November 2009 (Attachment P0104 to the Initial Regulatory Proposal), p27.

<sup>617</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p21; AER, Draft Determination, p285.

<sup>618</sup> Powercor Australia, Zone Substation Transformers Asset Management Plan, November 2009 (Attachment P0104 to the Initial Regulatory Proposal), p27.

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.<sup>619</sup> This would not be costless. Given the number of transformer types Powercor Australia could potentially be required to replace in a given period, the additional costs associated with this approach would be significant.<sup>620</sup>

Overall, SKM indicated that Powercor Australia's approach to energy at risk modelling is likely to **understate** energy at risk because:<sup>621</sup>

- Powercor Australia's energy at risk analysis uses the 50 per cent PoE demand forecasts, whereas in practice Powercor Australia 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;
- Powercor Australia 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); and
- Powercor Australia 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 Powercor Australia.

#### *Maximum demand forecasts*

As noted in Chapter 4, the AER rejected the maximum demand forecasts proposed by Powercor Australia in the 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 Powercor Australia's reinforcement capex forecasts in this Revised Regulatory Proposal are those included in its Initial Regulatory Proposal. These maximum demand forecasts are lower than the maximum demand forecasts reconciled with NIEIR's updated maximum demand forecasts that are presented in this Revised Regulatory Proposal. Accordingly, the maximum demand forecasts used for the purposes of forecasting reinforcement capex can be considered conservative. They are not likely to result in a systematic upward bias in the forecasts of reinforcement capex.

#### *Other matters raised by the AER*

Powercor Australia 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 Powercor Australia's forecasts of reinforcement capex. In any event, Powercor Australia develops its sub-transmission reinforcement capex forecasts solely by reference to energy at risk. In respect of its high and low voltage network, Powercor

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<sup>619</sup> The sources of these obligations are outlined in the Initial Regulatory Proposal, pp114-5.

<sup>620</sup> Powercor Australia 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 Powercor Australia 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.

<sup>621</sup> SKM, SKM Comments on Nuttall Consulting Report RE: Impact of Load Duration Curve, 9 July 2010 (Attachment 160 to this Revised Regulatory Proposal), p22.

Australia considers utilisation of the network and, in rural areas, seeks to ensure compliance with the voltage level requirements in the Distribution Code. The only exceptions are where, as discussed above, synergies can be extracted from reliability and quality maintained capex.

It is unclear what the AER means by its comments that Powercor Australia did not establish a clear link between the exercise of engineering judgment and the economic efficiency of the resultant forecast of reinforcement capex.<sup>622</sup> 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 Powercor Australia in forecasting reinforcement capex are set out in the material projects templates relating to major reinforcement capex projects,<sup>623</sup> demonstrate the economic efficiency of these forecasts of reinforcement capex, and thus support the methodology used by Powercor Australia.

### **9.8.3.3 Reinforcement projects proposed by Powercor Australia**

As noted above, the AER accepted Nuttall Consulting's assessment that there was a moderate probability (62 per cent) of Powercor Australia's reinforcement capex being required as proposed in the next regulatory control period.<sup>624</sup> However, Nuttall Consulting's methodology for determining the probabilities is flawed.

To reach its overall conclusion on the probability of Powercor Australia's reinforcement projects being required, Nuttall Consulting:<sup>625</sup>

- assigned to six 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 six projects being required across the remainder of the proposed reinforcement capex.

The errors in Nuttall Consulting's probability assessment are four fold. First, Nuttall Consulting's assessment of the six individual projects assessed is heavily reliant on Nuttall Consulting's engineering judgement and is flawed. As shown in Table 9.5 below, the six projects assessed by Nuttall Consulting 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,<sup>626</sup> Nuttall Consulting does not take into account the possibility that projects that are not currently reflected in Powercor Australia's forecasts may be brought forward to fall within the regulatory control period.

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<sup>622</sup> AER, Draft Determination, p335.

<sup>623</sup> Included in Attachment 161 to this Revised Regulatory Proposal.

<sup>624</sup> AER, Draft Determination, p324.

<sup>625</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p55.

<sup>626</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p176.



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Third, Nuttall Consulting's 'broader findings' do not justify a reduction in the assigned probabilities. This is because, as discussed in more detail above:

- in forecasting its reinforcement capex, Powercor Australia 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<sup>627</sup>); and
  - taken into account potential synergies and produced forecasts that are economically justified;
- Nuttall Consulting's criticisms of Powercor Australia's load profile and transformer outage duration assumptions are not justified. Further, overall, SKM found that Powercor Australia's approach to energy at risk modelling is likely to **understate** energy at risk;
- the maximum demand forecasts used by Powercor Australia in preparing its reinforcement capex forecasts are conservative; and
- Powercor Australia 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 six major projects across Powercor Australia's entire reinforcement capex. These projects make up only 21 per cent of Powercor Australia's total reinforcement capex.

Powercor Australia submits that the 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	Powercor Australia response
Eagle Hawk zone substation upgrade	The energy at risk calculations suggest the timing of the project is reasonable and the options considered are reasonable. <sup>628</sup> However, given the load profile assumptions, there is a reasonable possibility that this project may be optimally deferred. <sup>629</sup> Moderate to high probability of being required as proposed (70%).	Powercor Australia's load profile (or load duration curve) assumptions are reasonable (see discussion above). Accordingly, in circumstances where Nuttall Consulting accepted that, on the energy at risk calculations, the forecast timing and consideration of options was reasonable, and did not raise any other concerns regarding the project, there is no basis for discounting of the probability of the project proceeding. The project should be assigned 100% probability of being required as proposed.
Gisborne new zone substation	It is not clear that Powercor Australia's energy at risk calculations support the timing of the project. <sup>630</sup> Further, the AER's maximum demand forecasts and Powercor Australia's	Powercor Australia has provided the calculations of the expected value of energy at risk in the material projects template relating to this project. <sup>634</sup> These calculations support the timing of the project. The maximum demand forecasts

<sup>627</sup> Nuttall Consulting, Report - Capital Expenditure, 4 June 2010, p303.

<sup>628</sup> Nuttall Consulting, Report - Capital Expenditure, 4 June 2010, p178.

<sup>629</sup> Nuttall Consulting, Report - Capital Expenditure, 4 June 2010, p178.

<sup>630</sup> Nuttall Consulting, Report - Capital Expenditure, 4 June 2010, p178.



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Project reviewed	Nuttall Consulting assessment	Powercor Australia response
	<p>load profile assumptions mean that the project may well be deferred.<sup>631</sup></p> <p>Lower cost options (for example, the first stage of a switching station at Gisborne) have not been adequately considered.<sup>632</sup></p> <p>Low probability of being required as proposed (33%).<sup>633</sup></p>	<p>underpinning Powercor Australia's reinforcement capex are conservative and Powercor Australia's load duration curve assumptions are reasonable (see discussion above). It is not appropriate, therefore to assume a deferral of the project is likely on the basis of either of these assumptions.</p> <p>The material projects template shows that there are no lower cost options.</p> <p>Significantly, as noted in the confidential CIC meeting minutes of 1 June 2010<sup>635</sup> this project has been approved through Powercor Australia's internal governance processes (the same processes which Nuttall Consulting considers have resulted in efficient capex in the current regulatory control period<sup>636</sup>) and no lower cost options were identified.</p> <p>Accordingly, the project should be assigned 100% probability of being required as proposed.</p>
Bendigo terminal station to Charlton zone substation (BETS-CTN) 66kV line upgrade	<p>The AER's maximum demand forecasts suggest that this project may be deferred and lower cost options have not been adequately considered.<sup>637</sup> For example, there may be options linked with the staged upgrade of the line (such as the installation of reactive compensation) or alternatives such as the construction of a new line from KGTS to CTN.<sup>638</sup></p> <p>Moderate probability of being required as proposed (50%).<sup>639</sup></p>	<p>As noted above, the maximum demand forecasts underpinning Powercor Australia's reinforcement capex are conservative and it is therefore not appropriate to assume a deferral of the project on the basis of these forecasts.</p> <p>Powercor Australia has provided to the AER a material projects template relating to this project.<sup>640</sup> The template shows that there are no lower cost options.</p> <p>Significantly, the first stages of this upgrade have been approved through Powercor Australia's governance processes (the same processes which Nuttall Consulting considers have resulted in efficient capex in the current regulatory control period<sup>641</sup>) and no lower cost options were identified.<sup>642</sup></p> <p>Accordingly, the project should be assigned 100% probability of being required as proposed.</p>
Geelong East (GLE) upgrade	The energy at risk calculations do not justify the project (specifically, it is not	Powercor Australia has provided the calculations of the expected value of energy at risk in the

<sup>634</sup> Included in Attachment 161 to this Revised Regulatory Proposal.

<sup>631</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p178.

<sup>632</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p178.

<sup>633</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p178.

<sup>635</sup> Powercor Australia, Minutes, Capital Investment Committee Meeting, 1 June 2010 (Attachment 168 to this Revised Regulatory Proposal), p3.

<sup>636</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p101; AER, Draft Determination, p303.

<sup>637</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p179.

<sup>638</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p179.

<sup>639</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p179.

<sup>640</sup> Included in Attachment 161 to this Revised Regulatory Proposal.

<sup>641</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p101; AER, Draft Determination, p303.

<sup>642</sup> Powercor Australia, Minutes to the Capital Investment Committee meeting, 11 August 2009.

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Project reviewed	Nuttall Consulting assessment	Powercor Australia response
	<p>clear they adequately allow for available load transfers).<sup>643</sup></p> <p>Further, Powercor Australia's load profile assumptions mean that the project is likely to be deferred.<sup>644</sup></p> <p>Moderate probability of being required as proposed (50%).<sup>645</sup></p>	<p>material projects template relating to this project.<sup>646</sup> These calculations demonstrate the need for the capex.</p> <p>As noted above, SKM found that Powercor Australia's load duration curves are reasonable. In any event, adjusting the load profile does not affect the optimal timing of the project (see the material projects template included in Attachment 161 to this Revised Regulatory Proposal). Accordingly, Powercor Australia's load profile assumptions do not provide a basis for discounting the probability of the project proceeding.</p> <p>Accordingly, the project should be assigned 100% probability of being required as proposed.</p>
<p>Geelong (GTS) subtransmission 66kV lines augmentation</p>	<p>The energy at risk calculations appear to support the timing of this project and the options considered appear reasonable.<sup>647</sup></p> <p>However, given Powercor Australia's load profile assumptions, there is a reasonable possibility this project may be deferred.<sup>648</sup></p> <p>High probability of being required as proposed (90%).<sup>649</sup></p>	<p>Powercor Australia's energy at risk calculations are shown in the material projects template for this project.<sup>650</sup> These calculations demonstrate the need for the project within the proposed timing.</p> <p>In any event, Nuttall Consulting accepted the forecast timing of this project and accepted that Powercor Australia's consideration of options were reasonable. Nuttall Consulting raised concerns only with respect to Powercor Australia's load profile assumptions.</p> <p>As noted above, SKM found that Powercor Australia's load profile assumptions are reasonable and it is therefore not appropriate to assume a deferral of the project on the basis of these.</p> <p>Accordingly, the project should be assigned 100% probability of being required as proposed.</p>
<p>Numurkah to Cobram East (NKA-CBE) 66kV line upgrade</p>	<p>Powercor Australia has not demonstrated that the energy at risk, allowing for all interim measures (for example load transfers and emergency generation), justifies the project.<sup>651</sup></p> <p>Powercor Australia also has not provided details of its assessment of the alternative of transferring load away from CBE via the construction of three new 22kV feeders and has not adequately considered other</p>	<p>Powercor Australia has provided the calculations of the expected value of energy at risk in the material projects template relating to this project (included in Attachment 161 to this Revised Regulatory Proposal). These calculations demonstrate the need for the project within the proposed timing.</p> <p>Powercor Australia notes that Nuttall Consulting's load curve analysis has no bearing on the energy at risk for this project, as the line is radial, and therefore has energy at risk for 365</p>

<sup>643</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p179.

<sup>644</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p179.

<sup>645</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p179.

<sup>646</sup> Included in Attachment 161 to this Revised Regulatory Proposal.

<sup>647</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp179-80.

<sup>648</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p180.

<sup>649</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p180.

<sup>650</sup> Included in Attachment 161 to this Revised Regulatory Proposal.

<sup>651</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p180.

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Project reviewed	Nuttall Consulting assessment	Powercor Australia response
	alternatives (for example, a smaller scale 22kV transfer project). <sup>652</sup> Moderate to high probability of being required as proposed (70%). <sup>653</sup>	days per year. Accordingly, the project should be assigned 100% probability of being required as proposed.

Table 9.5 Powercor Australia's response to Nuttall Consulting's individual project assessments

#### 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 Powercor Australia'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. Powercor Australia 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 projects included in Powercor Australia'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*'<sup>654</sup> (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 is heavily reliant on engineering judgement and is incorrect. For the reasons set out in Table 9.5 above, the projects reviewed 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 Powercor Australia'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

<sup>652</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p180.

<sup>653</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p180.

<sup>654</sup> AER, Draft Determination, pp311-2.

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not currently reflected in the Powercor Australia's forecasts may be brought forward to fall within the regulatory control period; and

- as discussed above, it is not reasonable to extrapolate the probabilities for six major projects across Powercor Australia's entire reinforcement capex.

### **9.8.4 Powercor Australia's Revised Regulatory Proposals**

The reinforcement forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 9.6 below.

	\$'000 (real 2010)					
Expenditure category	2011	2012	2013	2014	2015	Total
Reinforcements	55,783	57,783	63,740	65,198	71,173	313,678

Table 9.6 Reinforcement capex forecasts included in the Revised Regulatory Proposal

## **9.9 Reliability and quality maintained capex**

### **9.9.1 Powercor Australia'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 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, Powercor Australia provided to the AER material program templates for each activity within each reliability and quality maintained capex function code.<sup>655</sup> 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. Powercor Australia 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 Powercor Australia in its Initial Regulatory Proposal for the next regulatory control period are discussed in more detail below.

#### **9.9.1.1 Conductor replacement program**

In its Initial Regulatory Proposal, Powercor Australia included capex relating to an enhanced high voltage overhead conductor replacement works program.<sup>656</sup> Additional information regarding the program was included in the relevant material program template provided to the AER on 26 February 2010<sup>657</sup> and the Subtransmission and HV Conductors Asset Management Plan.<sup>658</sup>

The conductor replacement program was developed to prepare for anticipated increases in high voltage overhead conductor failures.<sup>659</sup> A total of 420 in-service conductor

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<sup>655</sup> Material program templates were provided to the AER by email on 26 February 2010 and 3 March 2010.

<sup>656</sup> Initial Regulatory Proposal, p110.

<sup>657</sup> Document titled 'PAL 150 Overhead Line Replacement'.

<sup>658</sup> This plan was provided to the AER by email on 24 December 2009.

<sup>659</sup> Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER by email on 26 February 2010), p1.

failures occurred on Powercor Australia's network between 2005 -09, an average of 84 per year.<sup>660</sup> As Powercor Australia's conductor population becomes older, the risk of conductor failures is expected to increase.

Conductor failures can arise due to a number of reasons including lightning strikes, conductor annealing, wind induced conductor vibration or a combination of corrosion and localised heating. These failures usually result from gradual deterioration caused by the combined effects of corrosion load and fault currents and external forces such as wind, rain and lightning. Climate change modelling indicates that both the frequency and intensity of extreme events is likely to increase over the next 40 years and the general increase in temperatures and decrease in rainfall is likely to make the consequence of failure (e.g. bushfire) more significant over this period.<sup>661</sup> The older the conductor population, the more deteriorated the conductor and the more susceptible the conductor are to failures.

The potential impacts of conductor failure (bushfire and public safety) are well known. The expected general increase in temperatures and decrease in rainfall over the next 40 years make the consequence of conductor failure more significant over this period.<sup>662</sup>

In the past, conductor replacement has been largely as a result of network augmentation, with some replacement based on condition (i.e. replacement of localised sections of conductor that have a history of failing or signs of deterioration sufficient to justify taking the conductor out of service).<sup>663</sup> The volume of conductor replaced through these processes has been relatively small.<sup>664</sup>

As Powercor Australia's conductor population ages, the current rate of replacement will not be sufficient to manage the risk of conductor failure going forward. In 2011 Powercor Australia is proposing to commence a program of works to replace high voltage overhead conductor installed before 1971 over a 40 year period.<sup>665</sup> The majority of conductor that was installed prior to 1971 is nearing the end of its expected service life.<sup>666</sup>

Powercor Australia forecast capex of \$20 million per year in the next regulatory control period for its enhanced conductor replacement program. Powercor Australia developed this forecast as follows:

- Assuming a nominal service life of 50 years for conductors in coastal areas and 80 years for all other areas, Powercor Australia conducted analysis which suggested that, on average, about 660km of lines would be identified for replacement each year.

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<sup>660</sup> Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER by email on 26 February 2010), p1.

<sup>661</sup> See the climate change modelling prepared by Maunsell, Climate Change Impact Assessment on Powercor Australia for the 2011-15 EDPR, 30 September 2009 (Attachment P0016 to the Initial Regulatory Proposal).

<sup>662</sup> See the climate change modelling prepared by Maunsell, Climate Change Impact Assessment on Powercor Australia for the 2011-15 EDPR, 30 September 2009 (Attachment P0016 to the Initial Regulatory Proposal).

<sup>663</sup> Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER by email on 26 February 2010), p1.

<sup>664</sup> Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER by email on 26 February 2010), p1.

<sup>665</sup> Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER by email on 26 February 2010), p1.

<sup>666</sup> The conductor installed before 1971 was installed between the early 1950s and mid 1960s. Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER on 26 February 2010), pp2-3.



- Based on a representative sample of conductor replacement projects undertaken in 2009, Powercor Australia estimated that replacing 660 kilometres of line in a staged program would cost, on average, approximately \$27 million.
- On the basis that there would likely be some other reasons why conductors would need to be replaced (such as augmentations of capacity and line relocations), Powercor Australia considered it prudent to allow for replacement of less than 660 kilometres of line through the conductor replacement program to account for synergies between its conductor replacement program and its other capex programs. Specifically, Powercor Australia assumed an average 484 kilometres of conductors would be replaced under the program each year in the next regulatory control period, at a cost of \$20 million per annum.

The program will prioritise the 38 towns identified by the Victorian Government as high risk fire towns, as well as conductor exposed to corrosive salt in coastal conditions.

Alternative options to the replacement of overhead conductor include undergrounding, which is prohibitively expensive, or ongoing maintenance and repair of damaged conductors. The latter includes significant costs for the management of affected customers and liability issues. Powercor Australia's approach is intended to optimise the reasonable spread and mix of costs of on-going maintenance and capital investment for replacement.<sup>667</sup> The risk associated with not implementing the proposed replacement program is that the increasing number of deteriorated conductors that require replacement will lead to a potentially unmanageable conductor replacement program in future. This would result in untenably high total (opex and capex) costs.

#### **9.9.1.2 Zone substation replacement**

Powercor Australia forecast its capex required for zone substation replacement in the next regulatory control period using a CBRM model.

The CBRM methodology was developed and supplied to Powercor Australia by EA Technology. It provides a systematic framework to quantify the current or future condition, performance and risk of assets so that the need for replacement or refurbishment works can be identified. The CBRM model determines the probability of asset failure based, generally, on a 'health index' (HI). As the probability of failure increases the HI increases.

On 26 February 2010, Powercor Australia provided to the AER by email:

- a Memo from EA Technology which confirmed the appropriateness of the inputs used in the CBRM model; and
- material program templates in respect of function code 157 (which relates to zone substation replacement capex). This included templates relating to transformer replacement, transformer refurbishments and circuit breaker replacement (66kV and 22kV).

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<sup>667</sup> Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER by email on 26 February 2010), p1.



### **9.9.1.3 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, Powercor Australia 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, Powercor Australia provided to the AER material program templates for all zone substation secondary replacement activity.<sup>668</sup>

One of the more significant programs under this category of expenditure is relay replacement.<sup>669</sup>

### **9.9.1.4 Reliability replacement**

Reliability replacement relates to work to address worst served customers. Subsequent to the Initial Regulatory Proposal, Powercor Australia provided details of its reliability replacement programs, including works to address:<sup>670</sup>

- the worst performing 22kV feeders;
- 22kV feeders serving worst served customers;
- dead spots on 66kV lines;
- the worst performing 66kV lines; and
- asset related issues that are not addressed through existing fault follow up processes.

### **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.<sup>671</sup>

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.<sup>672</sup> The Repex Model uses age as a proxy for the many factors that drive individual asset replacements.<sup>673</sup>

The Repex Model assumes that recent historic replacement levels are reflective of the prudent and efficient management of the asset base<sup>674</sup> and '*was ... calibrated so that it reflected historical levels and costs*'<sup>675</sup>.

In its Draft Determination, the AER used the Repex Model forecasts:<sup>676</sup>

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<sup>668</sup> Each of the material program templates under function code 156 provided to the AER by email on 26 February 2010.

<sup>669</sup> Document titled 'PAL Ageing\_Unreliability Relay Replacement', provided to the AER by email on 26 February 2010.

<sup>670</sup> See templates relating to function code 172, provided to the AER on 3 March 2010.

<sup>671</sup> AER, Draft Determination, p339.

<sup>672</sup> AER, Draft Determination, p339.

<sup>673</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p29.

<sup>674</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p29.

<sup>675</sup> AER, Draft Determination, p339.

<sup>676</sup> AER, Draft Determination, pp338-9.

- as a check on the DNSPs' proposed reliability and quality maintained expenditure; and
- in a number of the above categories of reliability and quality maintained expenditure, as a substitute forecast for the proposed forecast.<sup>677</sup>

The AER raised concerns with, and reduced the allowance for, the following items of reliability and quality maintained expenditure:<sup>678</sup>

- conductor replacement program;
- zone substation plant replacement;
- zone substation secondary systems replacement;
- overhead and underground line replacement;
- HV and LV switch replacement; and
- reliability 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 Conductor replacement program**

The AER recognised that the recent 2009 experience of bushfires in Victoria demonstrates that a case can be made for enhanced expenditure on conductor replacement and historical expenditure alone is unlikely to be the best guide to the efficient level of capex.<sup>679</sup>

However, the AER reduced Powercor Australia's proposed expenditure in the next regulatory period by \$62.3 million (or around 60 per cent).<sup>680</sup> While the description appearing in the AER's Draft Determination is somewhat unclear,<sup>681</sup> the calculations provided to Powercor Australia show that, in determining the amount to be substituted for Powercor Australia's forecasts, the AER:<sup>682</sup>

- used the estimated quantity of conductor replacement reflected in Powercor Australia's Initial Regulatory Proposal;
- applied a unit cost of \$20.60 (rather than the rate of \$40.60 proposed by Powercor Australia); and
- then reduced the resultant total by a further 20 per cent.

The AER indicated in its Draft Determination that it applied an average unit costs rate rather than Powercor Australia's rate because it '*considered the proposed unit costs to be on the high side.*'<sup>683</sup>

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<sup>677</sup> Zone substation plant replacement, zone substation secondary systems replacement and HV switch replacement.

<sup>678</sup> AER, Draft Determination, pp356-66.

<sup>679</sup> AER, Draft Determination, p358.

<sup>680</sup> AER, Draft Determination, p366.

<sup>681</sup> AER, Draft Determination, p358.

<sup>682</sup> AER, 'Conductor model – PowerCor', provided to Powercor Australia by the AER on 7 June 2010.

<sup>683</sup> AER, Draft Determination, p358.

It appears that the AER reduced the forecast for the program by 20 per cent on the basis that the AER believed that Powercor Australia 'will be able to achieve 80 per cent accuracy' in targeting the conductors to be replaced to address bushfire risk.<sup>684</sup>

#### **9.9.2.2 Zone substation replacement**

The AER agreed with Nuttall Consulting that Powercor Australia's CBRM forecast does not reflect Powercor Australia's future replacement needs.<sup>685</sup> The AER indicated (references excluded) that:<sup>686</sup>

*'[the CBRM] modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of the assets will occur prior to any replacements being approved.'*

Nuttall Consulting also raised concerns with the inputs and assumptions of the CBRM. Specifically, Nuttall Consulting did not accept the following:<sup>687</sup>

- the current HI of the transformers, which it indicated may not be consistent with the results of Powercor Australia's polymerization test on the condition of transformers;
- the assets life assumption in respect of circuit breakers, the derivation of which it indicated is not clear; and
- the international failure probability rates for transformers and circuit breakers, which it indicated may not be consistent with Powercor Australia's historical data.

In respect of circuit breakers, Nuttall Consulting noted that it is not clear how Powercor Australia has derived the number of replacements from the model outputs.<sup>688</sup>

To demonstrate the suitability of the CBRM to forecasting zone substation plant replacement in the next regulatory control period, Nuttall Consulting indicated Powercor Australia would require:<sup>689</sup>

*'a far more substantial and quantitative analysis... [including] network level and sample asset level analysis that shows that the number of failures, probability of failure, the aging relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account Powercor's historical information, including failures statistics, asset condition monitoring results and risk mitigation measures.'*

Nuttall Consulting recommended an allowance based on average expenditure over 2006-08, with an increase based on the Repex Model.<sup>690</sup>

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<sup>684</sup> AER, Draft Determination, p358.

<sup>685</sup> AER, Draft Determination, p360.

<sup>686</sup> AER, Draft Determination, p360.

<sup>687</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp189-90; AER, Draft Determination, p360.

<sup>688</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p190.

<sup>689</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p191.

<sup>690</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp191 and 205.

### **9.9.2.3 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.<sup>691</sup>

The AER raised concerns in respect of the projected costs of the replacement of aged relays (which constituted 8 per cent of the reliability and quality maintained expenditure on zone substation secondary systems replacements forecast in the Initial Regulatory Proposal).<sup>692</sup> 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 Powercor Australia did not.<sup>693</sup>

Regarding the current and proposed programs more generally, the AER indicated that:<sup>694</sup>

- Powercor Australia 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 Powercor Australia 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
- Powercor Australia 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.<sup>695</sup>

### **9.9.2.4 Reliability replacement**

The AER rejected Powercor Australia's proposed reliability expenditure in its entirety on the basis that:<sup>696</sup>

- Powercor Australia 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 Powercor Australia 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
- Powercor Australia has not adequately demonstrated how its engineering judgment has been reflected in the expenditure forecasts.

The AER endorsed Nuttall Consulting's conclusion that:<sup>697</sup>

*'as expenditure is not captured to this activity code prior to 2009, it is not clear how similar works have been allocated historically. However, assuming that*

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<sup>691</sup> AER, Draft Determination, pp361-2.

<sup>692</sup> AER, Draft Determination, p361; Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p192.

<sup>693</sup> AER, Draft Determination, p361.

<sup>694</sup> AER, Draft Determination, pp361-2.

<sup>695</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p205.

<sup>696</sup> AER, Draft Determination, p365.

<sup>697</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p197; AER, Draft Determination, p365.

*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 our suggested forecasts for other activity codes, which are predominantly based upon an extrapolation of the 2006-08 costs.'*

### **9.9.3 Powercor Australia response to the AER's Draft Determination**

Powercor Australia 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, Powercor Australia has adopted the amounts in the AER's Draft Determination in respect of the following reliability and quality maintained programs:

- overhead and underground line replacement; and
- HV and LV switch replacement.

Powercor Australia 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.

Powercor Australia 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 Powercor Australia's forecasts. Removing the two major drivers of the increase in Powercor Australia's forecast in the next regulatory control period (the conductor replacement and reliability programs), which PB considered should be evaluated as step change increases, PB concluded that the variation between the calibrated Repex Model and Powercor Australia's forecasts did not justify an adjustment to Powercor Australia's proposed forecast.

Powercor Australia 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, Powercor Australia 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, Powercor Australia has used transparent, bottom-up build processes to produce efficient and prudent reliability and quality maintained forecasts for the next regulatory control period. By contrast, Powercor Australia notes that the AER's Repex Model is a 'black box' proprietary model.<sup>698</sup>

#### **9.9.3.1 The AER's Repex Model and its application in the Draft Determination**

Powercor Australia 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, Powercor Australia engaged PB to consider the AER's approach to assessing Powercor Australia's reliability and

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<sup>698</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p11.



quality maintained capex forecasts for the next regulatory control period.<sup>699</sup> Powercor Australia also invited EA Technology to comment on the AER's Draft Determination and the underlying Nuttall Consulting report.<sup>700</sup>

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:<sup>701</sup>

*'...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.<sup>702</sup> Further, EA Technology observed that the Repex Model 'uses coarser granularity than the Ofgem model' (on which it is based).<sup>703</sup> Specifically, 'distribution assets are broken down into 11 categories, compared with 68 asset classes used by Ofgem'.<sup>704</sup>

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.<sup>705</sup> PB stated:<sup>706</sup>

*'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).'*

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<sup>699</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal).

<sup>700</sup> 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).

<sup>701</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pvi.

<sup>702</sup> 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.

<sup>703</sup> 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.

<sup>704</sup> 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.

<sup>705</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p13.

<sup>706</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p13.



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.<sup>707</sup> 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.<sup>708</sup>

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.<sup>709</sup>

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.<sup>710</sup> PB concluded that:<sup>711</sup>

*'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.'*

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.<sup>712</sup> Specifically, PB considered that:<sup>713</sup>

- the substitute forecast was not based on the regulatory proposal, but rather was based on the independently developed Repex Model results; and

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<sup>707</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp10-6.

<sup>708</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p10.

<sup>709</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p10-1.

<sup>710</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p11.

<sup>711</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p12.

<sup>712</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp12-3.

<sup>713</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp12-3.

- 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:<sup>714</sup>

- 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.<sup>715</sup> Therefore, PB concluded that '*using Repex model forecasts at the activity code level as an acceptance/rejection criterion is inappropriate*'.<sup>716</sup> PB considered that the wide variation (-63 per cent to +105 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*'.<sup>717</sup> 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.<sup>718</sup>

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*'.<sup>719</sup>

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.<sup>720</sup>

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

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<sup>714</sup> 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.

<sup>715</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p13.

<sup>716</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), piii.

<sup>717</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p21.

<sup>718</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p14.

<sup>719</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), piii.

<sup>720</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p14.

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by Powercor Australia and the total replacement forecast predicted by the calibrated Repex Model. This is shown in Table 9.7 below.

Activity Code	Nuttall Consulting View	Powercor Proposed	Calibrated Repex Model	Nuttall Recommended
Cross Arm	Accepted	40.9	84.0	40.9
Conductor Replacement Program	Rejected – no allowance	125.7	-	-
Fault Related	Accepted	68.5	94.8	68.5
HV Fuse Unit & Surge Diverter	Accepted	14.5	20.1	14.5
HV Switch	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	6.8	2.2	2.2
OH/UG Line	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	19.6	10.0	10.0
Pole	Accepted	3.7	6.1	3.7
Pole	Accepted	69.0	73.3	69.0
Reliability Improvement	Rejected – no allowance	9.5	0.0	0.0
Services	Accepted	16.1	8.6	16.1
Transformer	Accepted	6.3	11.2	6.3
Zone Substation Plant	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	44.1	24.4	24.4
Zone Substation Secondary Systems	Rejected – allowance based upon average 2006-2008, with increase based upon Repex model findings	39.2	14.4	14.4
<b>Total</b>		<b>464.1</b>	<b>349.1</b>	<b>270.1</b>
	Rejected categories (no allowance)	(135.2)	-	-
<b>Total</b>	<b>(ex rejected categories)</b>	<b>328.8</b>	<b>349.1</b>	<b>270.1</b>

Source: Nuttall Report p.205 & PB Analysis of AER Repex Powercor.xls

**Table 9.7 PB summary of results (\$m 2010)<sup>721</sup>**

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:<sup>722</sup>

- 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;

<sup>721</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p20.

<sup>722</sup> 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:<sup>723</sup>

*'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.<sup>724</sup>

In any event, even if the calibrated Repex Model is assumed to produce reasonable forecasts for the next regulatory control period, Powercor Australia observes that PB found that the Repex Model supports Powercor Australia's forecasts (excluding its step change conductor replacement and its reclassified reliability replacement programs).

After removing the conductor program and reliability replacement programs, PB found that Powercor Australia's proposed capex is approximately 6 per cent **lower** than the total expenditure forecast by the calibrated Repex Model.<sup>725</sup> PB stated:<sup>726</sup>

*'In PB's opinion a 6% variation between a 'top down' forecast modelled on asset age and a 'bottom-up' forecast taking into specific account ...asset condition, risk and obsolescence as identified in PAL'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 Powercor Australia, it was not clear to PB why the 'top-down' Repex Model forecast is adopted as a reasonable base over Powercor Australia's 'bottom-up' proposal.<sup>727</sup> Accordingly, PB concluded that, on the assumption that the calibrated Repex Model is a reasonable and unbiased estimate of Powercor Australia's future total replacement capex:

- the submitted proposal, excluding the conductor replacement and reliability replacement programs, should be accepted as a reasonable baseline forecast of the replacement capex needs of Powercor Australia and no further reliance on the Repex Model is required; and

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<sup>723</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p14.

<sup>724</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p15.

<sup>725</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p20.

<sup>726</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p21.

<sup>727</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p21.

- consistent with the intent of Nuttall Consulting's methodology, the two excluded programs (i.e. conductor replacement and reliability replacement) should be evaluated as step change increases on the basis of the fundamental need, risks and the consideration of alternative options.<sup>728</sup>

Powercor Australia 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 Powercor Australia 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 Powercor Australia'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, the total forecast resulting from Nuttall Consulting's Repex Model is around six per cent higher than Powercor Australia's Initial Regulatory Proposal.<sup>729</sup> Thus, if it is assumed that the Repex Model is a reasonable unbiased estimate of Powercor Australia's future total replacement expenditure, Powercor Australia'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.<sup>730</sup>

#### **9.9.3.2 Impact of the AER's Draft Determination on opex**

If the AER reduces Powercor Australia's forecast reliability and quality maintained capex as proposed in the Draft Determination, the AER should allow additional opex to ensure that Powercor Australia is able to meet the NEO.

Powercor Australia 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.<sup>731</sup>

SKM modelled a range of scenarios, assuming:<sup>732</sup>

- the capex in Powercor Australia's Initial Regulatory Proposal was allowed;
- reductions in capex from Powercor Australia'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.<sup>733</sup> For instance, SKM found that, if Powercor Australia was allowed the capex amounts in the AER's Draft Determination, the

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<sup>728</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), pp21-2.

<sup>729</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p21.

<sup>730</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p22.

<sup>731</sup> SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal).

<sup>732</sup> SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), pp17-23.

<sup>733</sup> SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p4.



incremental increase in ageing of the network would require additional opex of \$6.04m over 2011-15.<sup>734</sup>

Adopting a conservative approach, however, Powercor Australia 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.

### **9.9.3.3 Powercor Australia's proposed reliability and quality maintained programs**

Powercor Australia 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.

#### *Conductor replacement program*

Subsequent to the submission of the Initial Regulatory Proposal, Powercor Australia engaged PB to provide an independent review of the risk associated with its overhead conductor assets and an assessment of the effective and efficient level of investment to mitigate this risk over an extended planning horizon.<sup>735</sup>

PB identified an existing risk in terms of the likelihood and consequences of conductor failures and an increasing risk to Powercor Australia's network and the health and safety of communities due to an ageing conductor population.<sup>736</sup> PB concluded that it is prudent and efficient to reduce the risk associated with conductor failures over the next 15 years and considered it prudent that Powercor Australia increase the level of conductor replacement.<sup>737</sup>

Powercor Australia's proposed conductor replacement program is intended to address this increasing risk. As noted in above, Powercor Australia is proposing an age-based approach, whereby it replaces conductors installed before 1971 over a 40 year period, targeting its program based on asset lives.

Powercor Australia submits an age-based approach to conductor replacement is prudent and efficient. Powercor Australia does not currently have a specific indicator of the condition or relative health of all sections of its overhead conductors. As noted by the independent expert, PB, this is not unusual because:<sup>738</sup>

- the overhead conductor asset categories are linear (i.e. there are no discrete sites to visit such as a zone substation, or even a pole);
- they cover an extensive route length that traverses a mixture of business, privately owned and public access locations; and

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<sup>734</sup> SKM, Impact of ageing assets on Powercor operating costs, 8 July 2010 (Attachment 138 to this Revised Regulatory Proposal), p23.

<sup>735</sup> PB, Overhead conductor replacement investment strategy, May 2010 (Attachment 252 to this Revised Regulatory Proposal), p4.

<sup>736</sup> PB, Overhead conductor replacement investment strategy, May 2010 (Attachment 252 to this Revised Regulatory Proposal), pp1 and 48.

<sup>737</sup> PB, Overhead conductor replacement investment strategy, May 2010 (Attachment 252 to this Revised Regulatory Proposal), pp48-9.

<sup>738</sup> PB, Overhead conductor replacement investment strategy, May 2010 (Attachment 252 to this Revised Regulatory Proposal), p14.



- there is limited information available at present from sampled predictive tests through which a technically accurate condition assessment of the wider population can be made.

As recognised by PB, expected asset life is an appropriate proxy for condition given the principle that overhead conductors exhibit wear out characteristics associated with the gradual and combined effects of failure modes caused by matters including atmospheric and galvanic corrosion, electrical arcing, conductor annealing, wind induced vibration, mechanical wear and damage from lightning and bird strikes, etc.<sup>739</sup>

As detailed above, Powercor Australia has proposed expenditure of \$20 million per annum over the next regulatory control period for the conductor replacement program. This level of expenditure is supported by PB. PB concluded that, of the options considered, an investment of \$20 million per annum maximises the net present value in 14 of the 15 sensitivity cases it examined.<sup>740</sup>

Regarding the AER's Draft Determination, Powercor Australia maintains that the average unit cost of \$40.60 reflected in its Initial Regulatory Proposal is efficient. Subsequent to the submission of the Initial Regulatory Proposal, Powercor Australia's conductor replacement unit costs (which were used to develop the average unit cost of \$40.60<sup>741</sup>) were reviewed by the independent expert, PB. PB found that Powercor Australia's costs are reasonable and fall within the bounds of typical industry values.<sup>742</sup>

Other than to note that it is 'an average unit cost for conductors', the AER did not provide details of the calculations of the unit cost of \$20.60 it has used to determine its capex allowance for the conductor replacement program. The AER also did not produce evidence to show that the cost is a reasonable estimate of the costs that Powercor Australia will likely face in the next regulatory control period.<sup>743</sup> Given the unit cost is significantly lower than the average cost identified by Powercor Australia, which is based on rates that PB found were reasonable, Powercor Australia submits that the AER's unit cost assumptions do not reflect a realistic expectation of the conductor replacement costs Powercor Australia will face in the next regulatory control period. These unit cost assumptions should therefore not be used by the AER to determine Powercor Australia's replacement expenditure in the next regulatory control period in the AER's Final Determination.

Powercor Australia observes that the unit rates included in other DNSPs' regulatory proposals may not reflect the same activities that are reflected in Powercor Australia's unit rates. For example, the unit rates proposed by Powercor Australia provide for the necessary replacement of a proportion of poles and cross-arms associated with the replacement of overhead conductor. Powercor Australia understands that other Victorian DNSPs' proposals may include these costs elsewhere. The AER must take care to ensure that it is comparing like with like before imposing on Powercor Australia a unit cost of half of that proposed.

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<sup>739</sup> PB, Overhead conductor replacement investment strategy, May 2010 (Attachment 252 to this Revised Regulatory Proposal), p14.

<sup>740</sup> PB, Overhead conductor replacement investment strategy, May 2010 (Attachment 252 to this Revised Regulatory Proposal), p47.

<sup>741</sup> Document titled 'PAL 150 Overhead Line Replacement' (provided to the AER on 26 February 2010), p2.

<sup>742</sup> PB, Overhead conductor replacement investment strategy, May 2010 (Attachment 252 to this Revised Regulatory Proposal), p32.

<sup>743</sup> AER, Draft Determination, p358.

The AER also does not provide adequate justification for its reduction of the total allowance by 20 per cent. A mere assertion that Powercor Australia will only be able to achieve 80 per cent accuracy in targeting the conductors to be replaced to address bushfire risk is not a valid basis for reducing the allowed expenditure. The AER's proposed reduction would result in a proportionate reduction in the conductors replaced by the program but the accuracy with which Powercor Australia is able to target the program would remain unchanged. Any practical impediments to accurately targeting conductors at risk of failure should be reflected in the allowed expenditure. This is because a prudent and efficient operator may accept a degree of inaccuracy in a particular program where the costs of ensuring that the program is targeted with 100 per cent accuracy would outweigh the benefits of the improved accuracy. Powercor Australia submits that an age-based approach to conductor replacement, where there is no specific indicator of the condition of all sections of its overhead conductors is both prudent and efficient.

Powercor Australia notes that if the AER reduces the capex allowed for this program away from the amount proposed by Powercor Australia, Powercor Australia will necessarily reduce the scope of the program by reducing the number of replacements it makes in the next regulatory control period. If Powercor Australia then seeks to mitigate the increasing risks of failure (and associated bushfire starts) as a result of the ageing of its overhead conductors in future, rather than investing in conductor replacement smoothly over time under its proposed program, Powercor Australia will be required to abruptly and significantly increase its investment in conductor replacement. Powercor Australia considers that such a deferral of the program will lead to a potentially unmanageable conductor replacement program in future, which would result in untenably high total (opex and capex) costs.

#### *Zone substation replacement*

Since lodging the Initial Regulatory Proposal, Powercor Australia has identified additional zone substation replacement expenditure that will be required in the next regulatory control period. When a detailed scoping of the replacement works at the Sunshine zone substation were commenced in late 2009, it was discovered that a complete redevelopment would be more efficient than the partial redevelopment contemplated in the Initial Regulatory Proposal. As demonstrated in the material program template,<sup>744</sup> Sunshine zone substation is at the end of its life, at risk of imminent failure and thus posing risks to the health and safety of personnel. Preliminary feasibility work has begun and the new transformers for the zone substation have been included in the quantity of units currently out to tender. Powercor Australia has included the costs of this redevelopment in this Revised Regulatory Proposal, instead of the replacement works initially proposed.

Regarding the remainder of the zone substation replacement proposed in the Initial Regulatory Proposal, Powercor Australia maintains that the CBRM model is an appropriate tool for forecasting zone substation replacement capex in the next regulatory control period.

The inputs and assumptions used in the CBRM model are reasonable. Pursuant to the AER's Draft Determination, Powercor Australia invited EA Technology to comment

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<sup>744</sup> Included in Attachment 164 to this Revised Regulatory Proposal.

on the Draft Determination and Nuttall Consulting's report.<sup>745</sup> While the report by EA Technology primarily discusses the application of the CBRM methodology by CitiPower, as noted by EA Technology, the same methodology is applied by Powercor Australia to transformer and switchgear assets.<sup>746</sup>

Regarding Nuttall Consulting's rejection of the current HI of transformers,<sup>747</sup> EA Technology stated that:<sup>748</sup>

*'[B]y any individual measure, the transformer might appear to have some service life remaining. It is only by considering all relevant factors (age, observed condition, measured condition, expected service life, ageing rate, manufacturer type history, etc) that an accurate indication of remaining life can be obtained.'*

That is, the HIs in the CBRM model (which are determined by combining multiple measures of condition) are representative of the condition of the transformer, whereas a single measure (such as the results of Powercor Australia's polymerization test) is not.

For instance, taking the example of a CitiPower transformer that Nuttall Consulting discussed in its report,<sup>749</sup> EA Technology noted that the operating conditions of that unit are a particularly important consideration. The fact that the transformer is on hot standby (no load) and continues to gas highlights the relevance of considering operating conditions in conjunction with test results to arrive at a final HI.<sup>750</sup>

Further, EA Technology highlighted the importance of combining objective test data with subjective assessment in order to arrive at a reliable forecast of remaining life. EA Technology stated:<sup>751</sup>

*'CBRM models use multiple sources of information to forecast remaining service life as reliably as possible. In addition to direct measurements to objectively measure asset condition, it benefits from subjective observations made by asset managers and field staff.'*

*These observations are expressed as factors within the model to quantify subjective observations and apply them across large numbers of assets. In some cases, such as the example described above, these factors may well exert considerable influence over the predicted remaining life. In other cases, measured condition information will dominate. As with all CBRM factors, these are shown explicitly in the Calibration section of the model and can be inspected, challenged and modified if required.'*

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<sup>745</sup> 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).

<sup>746</sup> 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), p2.

<sup>747</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp189-90.

<sup>748</sup> 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), p3.

<sup>749</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p100.

<sup>750</sup> 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), p3.

<sup>751</sup> 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.

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Powercor Australia observes that its CBRM model spreadsheets were provided to the AER on 27 January 2010.

In respect of Nuttall Consulting's suggestion that the transformer failure rates in the CBRM model are too high,<sup>752</sup> EA Technology stated that the failure rates are 'many times below the average'.<sup>753</sup> EA Technology stated:<sup>754</sup>

*'The failure rate used for high voltage switchgear was 0.13% per annum. We are not aware of any internationally published failure rates against which to compare this figure. However, in EA Technology's experience the average failure rate for comparable assets in recent CBRM studies is 0.49%. The rate used by CitiPower is less than a third of this average rate.'*

*'For power transformers, the CIGRE International Survey on Failures in Large Power Transformers in Service concluded that the overall failure rate for power transformers with tapchangers not less than 20 years old was 1.5-2%. The higher figure is in line with EA Technology's experience of rates observed in previous CBRM studies for similar assets. The failure rate used in the CitiPower transformer model is 0.5%, i.e. between one quarter and one third of the published international rate.'*

EA Technology drew the following general conclusions regarding CitiPower's (and thus Powercor Australia's) application of the CBRM model:<sup>755</sup>

*'CitiPower have implemented a comprehensive, detailed and robust CBRM process to provide the high standard of information necessary to determine the most appropriate level of required investment. We therefore believe that the levels of investment identified using this process, based on the available information, are both prudent and justified. In our view, the proposed programme represents the lowest-cost investment plan to adequately manage the replacement of assets over the next regulatory control period.'*

Powercor Australia also notes that the AER accepted the capex proposed by Energex using the CBRM methodology in its Queensland Final Determination.<sup>756</sup> The expert engaged by the AER for the purposes of that review, PB, found that the processes and procedures Energex used for determining reliability and quality maintained expenditure (including the CBRM model) was reflective of good industry practice and its implementation should lead to a prudent and efficient outcome.<sup>757</sup>

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<sup>752</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p190.

<sup>753</sup> 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), p2.

<sup>754</sup> 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), p2.

<sup>755</sup> 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), p2.

<sup>756</sup> AER, Queensland, Draft distribution determination 2010-11 to 2014-15, 25 November 2009, Appendices, p477 (Attachment 158 to this Revised Regulatory Proposal).

<sup>757</sup> PB, Review of ENERGEX regulatory proposal for the period July 2010 to June 2015, 2009 (Attachment 159 to this Revised Regulatory Proposal), p38.

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The CBRM methodology is set out in Powercor Australia's Transformer and Switchgear Replacement Plan.<sup>758</sup> Regarding Nuttall Consulting's suggestion that it is not clear how Powercor Australia has derived the number of circuit breaker replacements from the model outputs,<sup>759</sup> Powercor Australia sets out, in Table 9.8 below, the CBRM model outputs, including the replacement year and the predicted HI at 2015 if the circuit breaker was left in service.

Item ID	Zone substation.	CB Type	Function	Replacement year	HI YO (2009)	HI at 2015
20001265	SU	LG1C	Bus CB	2012	7.59	10.12
20001243	SU	LG1C	SU002	2012	7.59	10.12
20001245	SU	LG1C	SU003	2012	7.59	10.12
20001247	SU	LG1C	SU004	2012	7.59	10.12
20001249	SU	LG1C	SU005	2012	7.59	10.12
20001251	SU	LG1C	SU008	2012	7.59	10.12
20001253	SU	LG1C	SU009	2012	7.59	10.12
20001255	SU	LG1C	SU010	2012	7.59	10.12
20001257	SU	LG1C	SU027	2012	7.59	10.12
20001259	SU	LG1C	SU097	2012	7.59	10.12
20001261	SU	LG1C	Trans CB	2012	7.59	10.12
20001263	SU	LG1C	Trans CB	2012	7.59	10.12
20000618	CRO	LG1C	CRO021	2013	6.60	9.18
20000619	CRO	LG1C	CRO022	2013	6.60	9.18
20000620	CRO	LG1C	CRO023	2013	6.60	9.18
20000621	CRO	LG1C	CRO031	2013	6.60	9.18
20000622	CRO	LG1C	CRO032	2013	6.60	9.18
20000623	CRO	LG1C	CRO033	2013	6.60	9.18
20000624	CRO	LG1C	CRO034	2013	6.60	9.18
20000757	GL	LG1C	Bus CB	2014 / 2015	6.60	8.8
20000749	GL	LG1C	GL025	2014 / 2015	6.60	8.8
20000750	GL	LG1C	GL011	2014 / 2015	6.60	8.8
20000751	GL	LG1C	GL012	2014 / 2015	6.60	8.8
20000752	GL	LG1C	GL021	2014 / 2015	6.60	8.8
20000753	GL	LG1C	GL022	2014 / 2015	6.60	8.8
20000754	GL	LG1C	GL023	2014 / 2015	6.60	8.8
20000755	GL	LG1C	GL024	2014 / 2015	6.60	8.8
20000756	GL	LG1C	Trans CB	2014 / 2015	6.60	8.8
20000758	GL	LG1C	Trans CB	2014 / 2015	6.60	8.8
20000962	MNA	LG1C	MNA021	2015	6.60	9.18
20000964	MNA	LG1C	MNA022	2015	6.60	9.18
20000966	MNA	LG1C	MNA024	2015	6.60	9.18
20000968	MNA	LG1C	MNA034	2015	6.60	9.18
20001002	NKA	HKCYB	NKA001	2011	6.60	9.05
20001004	NKA	HKCYB	NKA003	2011	6.60	9.05
20001006	NKA	HKCYB	NKA004	2011	6.60	9.05
20001008	NKA	HKCYB	NKA005	2011	6.60	9.05
20001026	PLD	HKCYB	PLD001	2010	6.60	9.32
20001197	STL	HKCYB	STL006	2011	6.60	8.91
20001199	STL	HKCYB	STL007	2011	6.60	8.91
20001335	WPD	LG1C	WPD011	2015++	6.60	9.34

<sup>758</sup> Attachment P0033 to the Initial Regulatory Proposal.

<sup>759</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p190.



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Item ID	Zone substation.	CB Type	Function	Replacement year	HI Y0 (2009)	HI at 2015
20001336	WPD	LG1C	WPD014	2015++	6.60	9.34
20001337	WPD	LG1C	WPD021	2015++	6.60	9.34
20001338	WPD	LG1C	WPD022	2015++	6.60	9.34
20001339	WPD	LG1C	WPD024	2015++	6.60	9.34

**Table 9.8 CBRM model output (circuit breaker replacement)**

In this Revised Regulatory Proposal, Powercor Australia is proposing to replace 22kV circuit breakers in accordance with the outputs of the CBRM model (shown in Table 9.8 above), with the exception of the Sunshine zone substation replacements identified for 2012. While the CBRM modelling indicates that 12 of the 22kV circuit breakers at the SU (Sunshine) zone substation require replacement, as discussed above, all 16 existing outdoor circuit breakers will be replaced as the SU zone substation is being refurbished and the outdoor kV switchyard will be replaced with an indoor 22kV switchboard.<sup>760</sup> While more detail is included in the relevant material program template, by way of summary, the physical constraints at the substation do not allow a combination of four outdoor and 12 indoor 22kV circuit breakers.<sup>761</sup>

On the basis of the above, Powercor Australia submits that the reliability and quality maintained capex forecast by Powercor Australia using the CRBM methodology is prudent and efficient.

While Nuttall Consulting suggested that to demonstrate the suitability of the CBRM, Powercor Australia would require ‘*a far more substantial and quantitative analysis*’,<sup>762</sup> as discussed in the ‘General issues’ section above, it is not legally permissible for the AER to establish threshold requirements for it to be satisfied that a DNSP’s capex reasonably reflects the capex criteria. On the evidence before it, the AER should be satisfied that Powercor Australia’s forecasts for zone substation replacement capex reflect the capex required by a prudent and efficient operator.

In the event the AER rejects Powercor Australia’s zone substation plant replacement capex in the next regulatory control period, Powercor Australia observes that, as discussed above, it would not be reasonable for the AER to substitute values based on historic capex with an adjustment determined by the Repex Model.

*Zone substation secondary systems replacement*

Powercor Australia 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 Powercor Australia to the AER by email on 26 February 2010. Each of the programs are driven by unique circumstances and risks. As noted above, a number of 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.

<sup>760</sup> See the material program template ‘NP157\_2015\_X SU (Sunshine) Zone Substation Rebuild’ included in Attachment 164 to this Revised Regulatory Proposal.

<sup>761</sup> See the material program template ‘NP157\_2015\_X SU (Sunshine) Zone Substation Rebuild’ included in Attachment 164 to this Revised Regulatory Proposal.

<sup>762</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p191.



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The zone substation secondary equipment on Powercor Australia'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:<sup>763</sup>

*'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 Powercor Australia's proposed zone substation secondary systems replacement 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<sup>764</sup> (and the associated HV Protection Sub-Code<sup>765</sup>), Chapter 5 of the Rules<sup>766</sup> and the Distribution Code (consistent with clause 6.5.7(a)(2) of the Rules).

These risks, and how they drive key zone substation replacement programs, are discussed further below.

As noted above, the AER raised concerns in respect of Powercor Australia's proposed relay replacement. Powercor Australia notes that the asset management plan relating to relay replacement was 'draft' at the time it was submitted to the AER. The plan has now been finalised.<sup>767</sup>

In commenting that the level of replacement in the next period is lower than the average level in the current period,<sup>768</sup> 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 2006-10 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

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<sup>763</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p38.

<sup>764</sup> Attachment 167 to this Revised Regulatory Proposal.

<sup>765</sup> Powercor Australia observes that the HV Protection Sub-Code (Attachment 166 to this Revised Regulatory Proposal) 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.

<sup>766</sup> Powercor Australia notes that it is required to comply with Chapter 5 of the Rules from 1 January 2011: clause 9.7 of the Rules.

<sup>767</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan (Attachment 255 to this Revised Regulatory Proposal).

<sup>768</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p193.

circuit breakers 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 template provided to the AER, across Powercor Australia's network, there are on average two relays for each scheme.<sup>769</sup> Accordingly, rather than indicating that Powercor Australia is proposing to reduce the number of relays replaced, as suggested by Nuttall Consulting,<sup>770</sup> the template provided to the AER indicated that on average, approximately 38.3 schemes (or 76.6 relays) were replaced per annum in 2006-10, with 55 schemes (or approximately 550 relays) per annum proposed for replacement in 2011-15.<sup>771</sup> That is, Powercor Australia is proposing an increase in the number of schemes (and thus relays) to be replaced in the next regulatory control period. The capex proposed by Powercor Australia for relay replacement is consistent with the proposed increase in the number of relays to be replaced.

The increase in relay replacement in the next regulatory control period is driven by Powercor Australia's RCM analysis, which is reflected in Powercor Australia's Protection Equipment (Relays) Asset Management Plan.<sup>772</sup> 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<sup>773</sup>). Powercor Australia notes that one of these risks is 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).<sup>774</sup>

In the next regulatory control period, Powercor Australia is proposing to replace:

- relays that were assigned a 'very high' overall risk score (assets which require replacement within 0-4 years);
- a large proportion of relays that were assigned a 'high' overall risk score (assets which require replacement within 4-8 years); and
- some relays that were assigned an 'elevated' overall risk score (assets which require replacement within 8-10 years).

Replacement of some relays assigned an 'elevated' overall risk score will be required where technical adequacy is insufficient and performance changes.<sup>775</sup> Regarding the number of relays with an 'elevated' overall risk score, Powercor Australia expects

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<sup>769</sup> Document titled 'PAL 156 – Ageing\_Unreliable Relay Replacement' (provided to the AER 26 February 2010), p1.

<sup>770</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p193.

<sup>771</sup> Document titled 'PAL 156 – Ageing\_Unreliable Relay Replacement' (provided to the AER 26 February 2010), p1.

<sup>772</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal).

<sup>773</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p20-1.

<sup>774</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p20.

<sup>775</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p21.

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approximately 10 per cent of the total relays population will move into the 'elevated' risk category over the next regulatory control period.<sup>776</sup>

Powercor Australia also considers that the most efficient way of upgrading relays is to concentrate on replacement by zone substation, rather than discrete individual relays across the entire network.<sup>777</sup> This is to ensure that isolated relays, which do not confirm with Powercor Australia's new standards,<sup>778</sup> are not left unchanged.<sup>779</sup> Based on past programs, Powercor Australia has estimated that this will increase the number of relays requiring replacement in the next regulatory control period by approximately 20 per cent.<sup>780</sup>

Powercor Australia has estimated that it will replace 55 schemes per annum (or approximately 550 relays) in the next regulatory control period.<sup>781</sup> This reflects:<sup>782</sup>

- replacement of approximately 300 relays classified as 'very high' risk;
- replacement of approximately 150 relays classified as 'high' risk;
- replacement of approximately 10 relays in the 'elevated' risk category; and
- replacement of approximately 90 relays to ensure that isolated relays are not left unchanged as the program is implemented.

Failure of one type of relay can affect hundreds of circuits in Powercor Australia's network. Powercor Australia estimates, on the replacement included in its Revised Regulatory Proposal, the 2010 level of 109 relays in the very high risk category will be broadly maintained by 2015, when an estimated 138 relays will be in this 'very high' risk category.<sup>783</sup> This is shown in Figure 9.1 below. This expenditure would ensure compliance 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 169 to 278.<sup>784</sup> This is also shown in Figure 9.1 below. Powercor Australia considers that this increase in the number of relays in this category would be inconsistent with the Distribution Code 'good asset management' obligations.

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<sup>776</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p22.

<sup>777</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p22.

<sup>778</sup> Powercor Australia's standards are outlined in its Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p11. That is, the Powercor Australia now procures relays with fully integrated microprocessor controlled sensing and actuation controlled by software.

<sup>779</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p22.

<sup>780</sup> Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), p22.

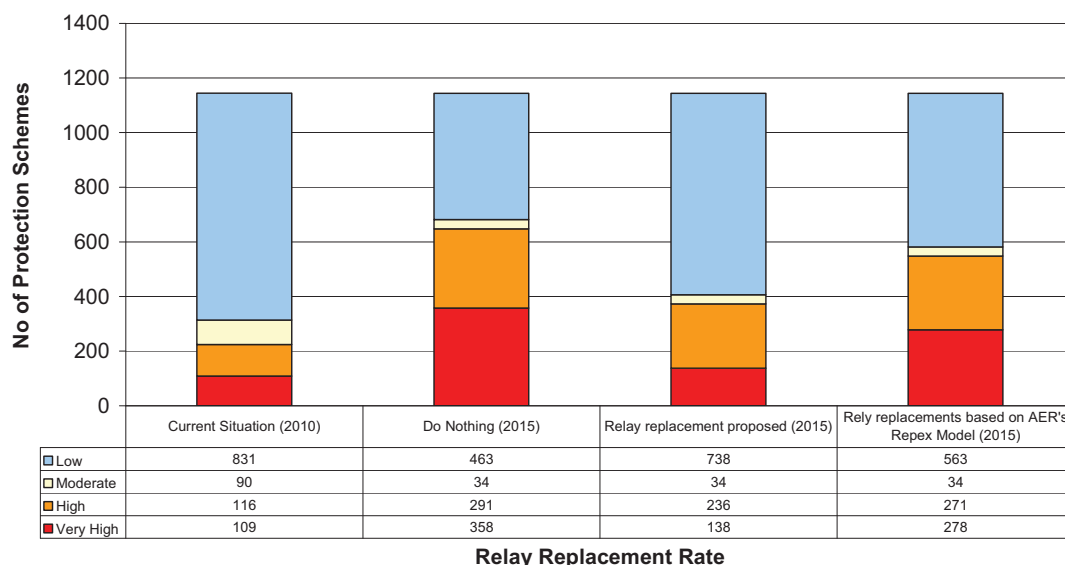
<sup>781</sup> Document titled 'PAL 156 – Ageing\_Unreliable Relay Replacement', provided to the AER by email on 5 March 2010.

<sup>782</sup> These figures can be determined by taking the total number of relays in Powercor Australia's network (approximately 3000) and the percentages of relays falling within each risk category shown in the relevant Asset Management Plan: Powercor Australia, Protection Equipment (Relays) Asset Management Plan, May 2010 (Attachment 255 to this Revised Regulatory Proposal), pp5 and 22.

<sup>783</sup> See material program template 'Ageing/Unreliable Relay Replacement Program – Zone Substations' (included in Attachment 164 to this Revised Regulatory Proposal).

<sup>784</sup> See material program template 'Ageing/Unreliable Relay Replacement Program – Zone Substations' (included in Attachment 164 to this Revised Regulatory Proposal).

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**Relay Replacement Rate**

**Figure 9.1 Powercor Australia relay risk profile (2010 and 2015)**

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On the information set out above, Powercor Australia 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 Powercor Australia's 2011-15 forecasts, Powercor Australia maintains that these are economically justified or are required to respond to increased risk on the network. In addition to the further material program templates included in Attachment 164 to this Revised Regulatory Proposal, Table 9.9 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 <sup>785</sup>	SP AusNet is proposing to upgrade its Geelong terminal station (GTS) and Keilor terminal station (KTS). 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, Powercor Australia's program includes non-discretionary replacement of x and y schemes at Powercor Australia zone substations that communicate to GTS and KTS (six lines in total). If Powercor Australia does not carry out the proposed replacement of relays at connecting zone substations then the protection systems will be compromised.
DC supplies, amp hour capacity and fusing upgrades for zone substations <sup>786</sup>	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 then all protection and control systems at zone substations will cease to operate and the zone substation can no longer be used as a supply point until the

<sup>785</sup> See document titled 'PAL 156 Augmentation associated with SPAusNet Projects' provided to the AER by email on 26 February 2010 and the material program template 'Augmentation Associated with SPAusNet Projects' (included in Attachment 164 to this Revised Regulatory Proposal).

<sup>786</sup> See documents titled 'PAL 156 – DC Supplies, AmpHour Capacity and Fusing Upgrades' (provided to the AER by email on 26 February 2010) and the material programs template 'Replacement Battery Banks and Charges' (included in Attachment 164 to this Revised Regulatory Proposal).

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Program	Explanation
	<p>DC systems are restored. If backup power fails then there is the risk of failure of all protection and control systems at zone substations.</p> <p>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.</p>
Control room modifications <sup>787</sup>	<p>Powercor Australia has a number of ageing control rooms, which can restrict the deployment of additional equipment and systems required for Powercor Australia's proposed protection and control works. For example, older control rooms may:</p> <ul style="list-style-type: none"> <li>• not allow for safe access to panels and equipment;</li> <li>• not have adequate space to house new equipment;</li> <li>• give rise to difficulties at commissioning due to the space constraints of temporary cubicles;</li> <li>• have inadequate cable trenches that restrict the level of cabling that can be deployed; and</li> <li>• not adequately manage humidity and condensation.</li> </ul> <p>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 environments.</p> <p>Deferral is no longer possible due to likely health and safety risks from the limited space now available.</p> <p>Upgrades have been proposed to ensure a safe, secure and effective control room environment.</p>
Duplicate protection on selected buses and circuit breaker backup schemes <sup>788</sup>	<p>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.</p> <p>Duplicate protection on 66kV buses and circuit breaker backup schemes have not been established across Powercor Australia's entire network. This program is designed to bring existing zone substations up to the same level of functionality as new installations.</p> <p>Powercor Australia has proposed these works to coincide with other proposed protection works. Powercor Australia is proposing three physicals per annum.</p> <p>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, Powercor Australia would not be able to achieve compliance with these mandatory obligations.</p>
Duplicate protection on selected feeders <sup>789</sup>	<p>Powercor Australia is proposing duplicate protection on 22kV feeders as required to meet backup protection reach. If primary protection fails and backup protection cannot clear a fault, there are significant consequences to public and employee safety, as well as damage to assets.</p> <p>The program is required to ensure that protection backup is maintained across Powercor Australia's network and to ensure that faults are isolated and cleared safely and efficiently. As loads continue to increase across the network, this has become more difficult to achieve through protection setting changes.</p>

<sup>787</sup> See document titled 'PAL 156 – Control Room Modification' provided to the AER by email on 26 February 2010.

<sup>788</sup> See document titled 'PAL 156 – Duplicate protection on Buses and CB Backup', provided to the AER by email on 26 February 2010.

<sup>789</sup> See document titled 'PAL 156 – Duplicate Protection on Selected Feeders', provided to the AER on 26 February 2010.



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Program	Explanation
Auto reclose implementation program on 66kV & 22kV buses <sup>790</sup>	<p>Powercor Australia is proposing auto reclose functionality on 66kV and 22kV zone substation buses.</p> <p>This program is associated with those zone substations supplying a mix of urban rural areas, focusing on those areas with a growing urban customer base.</p> <p>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.</p> <p>This program aims to improve Powercor Australia's zone substation security on a continuing basis across the network and to bring Powercor Australia in line with good engineering practice.</p>
Communications network radio/equipment replacements/upgrades <sup>791</sup>	<p>This program involves the replacement of ageing and unsupported radio communications equipment. Current radio communications equipment does not meet the current digital communications requirements for greater bandwidth demanded of SCADA systems.</p> <p>Powercor Australia is proposing to address approximately six communications devices per year over the next regulatory control period.</p> <p>The program is necessary to address the increased failure rates of unsupported radio communications equipment currently being experienced and to maintain the SCADA protection networks. The level of unplanned failure of communications devices needs to be better managed through a planned replacement program, such as the proposed program. Powercor Australia's proposed program will ensure network reliability is maintained and the health and safety risks are not increased. The program will also ensure that Powercor Australia complies with the 'good asset management' obligations in clause 3 of the Distribution Code.</p> <p>If the expenditure is cut in accordance with the AER's Draft Determination, Powercor Australia would face increased risk of failure of the analogue radio system, which would lead to extended outage times. The reduced expenditure would also increase the health and safety risks resulting from the loss of monitoring and control of zone substations. Finally, Powercor Australia would risk non-compliance with the 'good asset management' obligations under clause 3 of the Distribution Code.</p>
Replacement of supervisory cable with existing optical fibre cable <sup>792</sup>	<p>This program involves the replacement of communications equipment that use supervisory cable with fibre based systems.</p> <p>Powercor Australia has a number of supervisory cable systems and communications equipment that are required to be upgraded to be compatible with the new SCADA system and align with the <i>Network Protection and Communications Strategy 2009-2014</i>.<sup>793</sup> Some of this equipment is located in substations where fibre optic systems are available but not yet fully utilised.</p> <p>The existing communications systems support protection schemes, remote tripping between substations and monitoring and control applications via VF technologies. Due to changes in communication technology and upgrade of the SCADA system, the use of VF needs to be phased out and replaced with industry standard digital communication interfaces.</p>

<sup>790</sup> See document titled 'PAL 156 – Install Auto Reclose on 66kV and 22kV Buses' (provided to the AER on 26 February 2010).

<sup>791</sup> See document titled 'PAL 156 – Communications Network Equipment Replacements' (provided to the AER on 26 February 2010) and material program template 'Communications Network Radio/Equipment replacements/upgrades' (included in Attachment 164 to this Revised Regulatory Proposal).

<sup>792</sup> See document titled 'PAL 156 – Replacement of Supervisory Cable with Existing OFC' (provided to the AER by email on 26 February 2010) and material program template 'PAL 156 – Replacement of Supervisory Cable with Existing optical fibre cable' (included in Attachment 164 to this Revised Regulatory Proposal).

<sup>793</sup> Attachment P0030 to the Initial Regulatory Proposal.



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Program	Explanation
	<p>Powercor Australia forecasts are based on an average replacement of 10km per year over the next regulatory control period. This will ensure that the remaining overhead supervisory cable is replaced. The unit cost is based on an estimate of works for other like communications works (specifically work carried out for the Richmond terminal station to TK zone substation).</p> <p>The move to fibre optics and new technologies is prudent and consistent with good electricity industry practice. It will ensure:</p> <ul style="list-style-type: none"> <li>• equipment and system support can be maintained;</li> <li>• availability of spare parts;</li> <li>• technical adequacy;</li> <li>• network reliability is maintained;</li> <li>• improved visibility and maintenance of equipment and systems;</li> <li>• improved speed and data capability of communications;</li> <li>• standard protocols and interfaces are utilised;</li> <li>• increased distance for signalling; and</li> <li>• facilities are available for extended uses.</li> </ul> <p>Under its proposal, Powercor Australia will be able to maintain reliability by replacing supervisory and VF equipment that is approaching the end of its technically useful life and will be in compliance with its 'good asset management' obligations under clause 3 of the Distribution Code. Powercor Australia will also be able to ensure there are no increases to health and safety risks.</p> <p>However, under the AER's Draft Determination, Powercor Australia notes that there would be an increase risk of failure of the ageing supervisory and VF systems, leading to reduced network reliability. There would also be increased risks to health and safety due to increasing failures leading to loss of protection co-ordination between zone substations. Powercor Australia would also risk non-compliance with the 'good asset management' obligations under clause 3 of the Distribution Code.</p>

**Table 9.9 Key zone substations secondary system replacement programs included in Powercor Australia's Revised Regulatory Proposal**

*Reliability replacement*

Powercor Australia 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.

Powercor Australia believes that this level of expenditure is required to ensure compliance with Powercor Australia'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 attempt to 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.<sup>794</sup>

<sup>794</sup> PB, Repex Model Review, July 2010 (Attachment 171 to this Revised Regulatory Proposal), p23.

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To assist the AER with its consideration of Powercor Australia's Revised Regulatory Proposal, Powercor Australia provides further details in respect of each of its reliability replacement programs in Table 9.10 below.

Program	Explanation
22kV worst performing feeders <sup>795</sup>	<p>These works are required to address customer service issues arising from Powercor Australia's worst performing 22kV feeders. Powercor Australia proposes to address five of the worst performing feeders in each feeder category (urban, rural short and rural long) in each year of the next regulatory control period (i.e. 15 projects per annum).</p> <p>The feeders are selected on an annual basis from Powercor Australia's regular monitoring activities. Each feeder is investigated separately to determine what measures are most appropriate and effective.</p> <p>In 2009, 7 feeders were identified as having effective work packages that could address the localised service issue. The remaining feeders on the target list, which were not addressed in 2009, were dealt with by normal maintenance expenditure. Prior to 2009 there was no consolidated documentation of works at the program level (the only details are at the function code level).</p> <p>Powercor Australia is proposing works on 15 feeders per annum in the next regulatory control period. The works are required to address reliability issues on these worst served parts of the network.</p>
22kV worst served customers <sup>796</sup>	<p>These works are to address reliability for Powercor Australia's 22 kV worst served customers. The program focuses on isolated pockets or communities of customers who experience the worst reliability performance. This may involve communities at the end of a feeder experiencing poor performance where the total feeder performance may not be in the worst performing category and hence not part of another reliability replacement program.</p> <p>Reliability investigations are undertaken on the top 15 per cent of feeders that contribute to unplanned SAIDI. Approximately 60 to 70 feeders make up this list for analysis. Worst served customers are also identified by reports of performance downstream of the protective devices and by local interaction with communities.</p> <p>The works are required to address reliability issues on these worst served parts of the network.</p>
66kV 'dead spot' program <sup>797</sup>	<p>Infra red surveys are carried out on subtransmission lines to identify thermal defects and hot joints. However, parts of the lines are not covered due to geographical access limitations. These areas are referred to as 'dead spots'.</p> <p>These works involve replacing failed and obsolete connectors in dead spots on 66kV lines. The works are required to avoid outages due to connection failures and thus to maintain reliability levels.</p> <p>Powercor Australia is proposing to address approximately two line projects per annum.</p>
66kV projects <sup>798</sup>	<p>This program addresses the worst performing 66kV lines or sections of lines. Specifically, it addresses lines, parts of lines and particular structures that, while compliant with existing or previous standards, have risk of failure due to known issues, which risks can be reduced by additional targeted works.</p> <p>Powercor Australia's forecast is based on an average of eight projects per annum. The works are required to address reliability issues on these parts of the network.</p>
System event minor reliability	<p>This program involves addressing asset related issues that are not addressed through existing fault follow up processes, i.e., works that fall outside maintenance and FFU28 fault</p>

<sup>795</sup> See document titled 'PAL 172 – 22 kV Worst Performing Feeders' (provided to the AER by email on 3 March 2010).

<sup>796</sup> See document titled 'PAL 172 – 22 kV Worst Served Customers' (provided to the AER by email on 3 March 2010).

<sup>797</sup> See document titled 'PAL 172 – 66 kV Dead Spot Program' (provided to the AER by email on 3 March 2010).

<sup>798</sup> See document titled 'PAL 172 – 66kV Projects' (provided to the AER by email on 3 March 2010).

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Program	Explanation
projects <sup>799</sup>	<p>follow up policies and processes (to restore and repair within 28 days).</p> <p>In the course of addressing faults, additional work in a nearby area may be identified. For example, pole clearances may not be adequate on an adjacent structure or there may be a similar issue to that which caused the existing fault.</p> <p>The program is necessary to maintain reliability.</p>

Table 9.10 Key reliability programs included in Powercor Australia's Revised Regulatory Proposal

### 9.9.4 Powercor Australia's Revised Regulatory Proposal

The reliability, quality and maintained capex forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 9.11 below.

Expenditure category	\$'000 (real 2010)					
	2011	2012	2013	2014	2015	Total
Reliability and quality maintained	91,052	100,364	99,862	94,776	95,777	481,831

Table 9.11 Reliability and quality maintained capex forecasts included in Powercor Australia's Revised Regulatory Proposal

## 9.10 Environmental, safety and legal capex

### 9.10.1 Powercor Australia's Initial Regulatory Proposal

In its Initial Regulatory Proposal, Powercor Australia 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.<sup>800</sup>

Powercor Australia indicated that the main factors driving the increase in this category of capex from 2006-10 capex were:

- increased noise mitigation at zone sub-stations;
- expenditure on the management of powerline easements in Victorian national parks; and
- bushfire mitigation expenditure.<sup>801</sup>

### 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.<sup>802</sup>

The AER concluded that:<sup>803</sup>

- 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

<sup>799</sup> See document titled 'PAL 172 – System Event Minor Reliability Projects' (provided to the AER by email on 3 March 2010).

<sup>800</sup> Initial Regulatory Proposal, p112.

<sup>801</sup> Initial Regulatory Proposal, p121.

<sup>802</sup> AER, Draft Determination, p399.

<sup>803</sup> AER, Draft Determination, p402.

- 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.<sup>804</sup> The AER noted the project explanations provided by Powercor Australia, but indicated these were not linked to any risk assessment in support of an overall works program.<sup>805</sup>

The AER therefore rejected Powercor Australia's proposed environmental, safety and legal capex forecasts and substituted amounts based on a continuation of historical trend in this capex category.<sup>806</sup> 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).<sup>807</sup>

### **9.10.3 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia 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, Powercor Australia considers that the AER should include 2009 actual data:

- in its trend analysis; and
- in forecasting the environmental, legal and safety capex required in the next regulatory control period by reference to historical expenditure.

Powercor Australia notes that, as demonstrated by Figure 9.2 below, when data beyond 2004-08 (including 2009 actual data) is incorporated into the analysis, the AER's conclusion that Powercor Australia's actual capex follows a gradually increasing trend is less compelling.

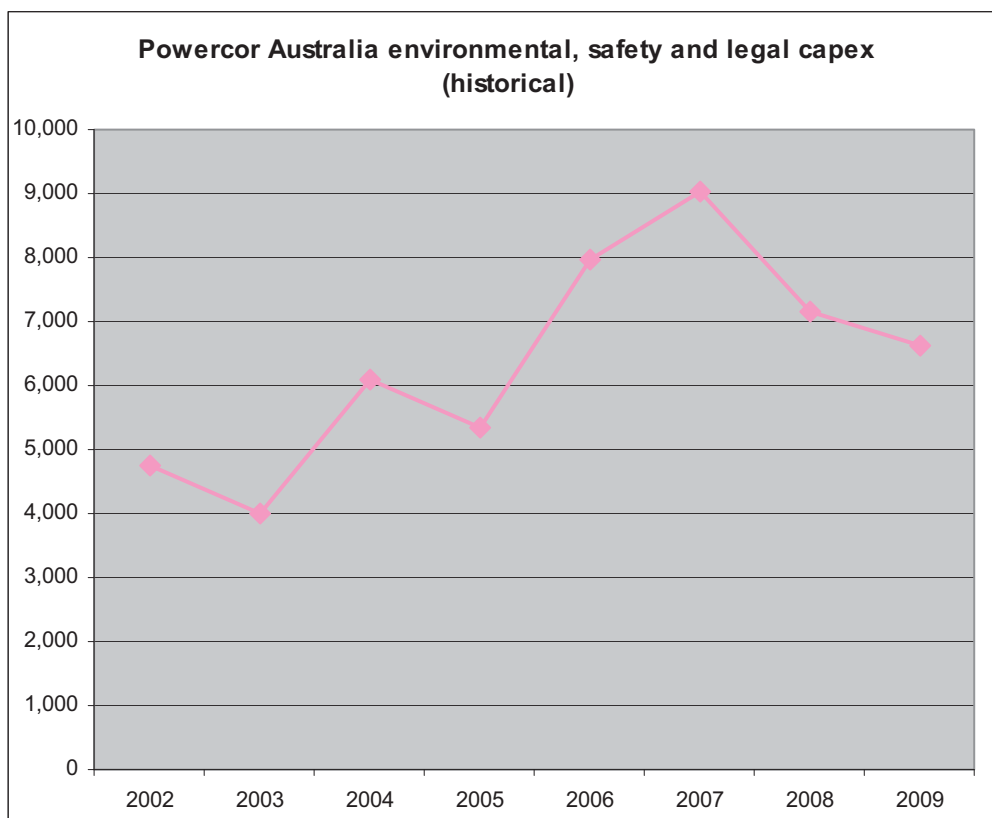
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<sup>804</sup> AER, Draft Determination, p401.

<sup>805</sup> AER, Draft Determination, p402.

<sup>806</sup> AER, Draft Determination, pp394-404.

<sup>807</sup> AER, Draft Determination, p400.



**Figure 9.2 Powercor Australia's historical environmental, safety and legal capex (real \$'000)**

Powercor Australia notes that, if the AER makes its Final Determination consistent with its Draft Determination, Powercor Australia will not be in a position to complete all of the noise works contemplated in its Initial Regulatory Proposal.<sup>808</sup>

Powercor Australia 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.

Finally, as discussed in further detail in Chapters 6 and 17 of this Revised Regulatory Proposal, Powercor Australia considers the plans submitted under the Electrical Safety Management Regulations should be addressed by the AER as a nominated pass through.

#### **9.10.4 Powercor Australia Revised Regulatory Proposal**

The environmental, safety and legal capex forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 9.12 below.

<sup>808</sup> Initial Regulatory Proposal, p114.

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Expenditure category	\$'000 (real 2010)					Total
	2011	2012	2013	2014	2015	
Environmental, safety & legal	8,211	8,352	8,456	8,527	8,595	42,141

Table 9.12 Environmental, safety and legal capex forecasts included in Powercor Australia's Revised Regulatory Proposal

## 9.11 SCADA and network control capex

### 9.11.1 Powercor Australia's Initial Regulatory Proposal

Powercor Australia's Initial Regulatory Proposal included SCADA and network control capex.<sup>809</sup> The proposed SCADA and network control capex program included provision for the following:<sup>810</sup>

- continuation of the installation of new protection and control communications infrastructure, which CitiPower and Powercor Australia 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 Powercor Australia'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;
- migration away from TMR, which is an old mobile radio technology, to SCADA; and
- increased substation monitoring and automation investments.

Powercor Australia 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.<sup>811</sup> The AER also commented that each DNSP underspent its benchmark allowance in the current regulatory control period.<sup>812</sup>

The AER indicated that Powercor Australia had not justified the significant increase in forecast SCADA and network control required for the next regulatory control period.<sup>813</sup> The AER commented that, because DNSPs have discretion to prioritise their work program, each DNSP underspent relative to the ESCV benchmark allowance on the basis that it considered it efficient to do so.<sup>814</sup>

In assessing Powercor Australia's proposed SCADA and network control capex, Nuttall Consulting stated that the DMS field devices installation program identified by Powercor Australia is captured in proposed non-network – IT capex.<sup>815</sup> Consequently, Nuttall Consulting did not assess it in the SCADA and network control section of its

<sup>809</sup> Initial Regulatory Proposal, pp121-30.

<sup>810</sup> Initial Regulatory Proposal, p123.

<sup>811</sup> AER, Draft Determination, p409.

<sup>812</sup> AER, Draft Determination, p410.

<sup>813</sup> AER, Draft Determination, pp411-2.

<sup>814</sup> AER, Draft Determination, p411.

<sup>815</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p211.



report<sup>816</sup> and the AER did not refer to the installation of the DMS field devices in its Draft Determination.<sup>817</sup>

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.<sup>818</sup> The AER also did not consider that Powercor Australia had linked the majority of the proposed projects to the Network Protection and Control Communications Strategy 2009-2014.<sup>819</sup>

The AER therefore rejected Powercor Australia's proposed SCADA and network control forecasts and substituted amounts based on a continuation of historical trend in this capex category.<sup>820</sup> 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).<sup>821</sup>

### **9.11.3 Powercor Australia's response to the AER's Draft Determination**

For the reasons outlined in the 'General issues' section above, Powercor Australia considers that the AER should include 2009 actual data in its trend analysis and in determining an amount that is consistent with historical capex.

Powercor Australia 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 Powercor Australia's actual capex follows a gradually increasing trend is less compelling.

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<sup>816</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p211.

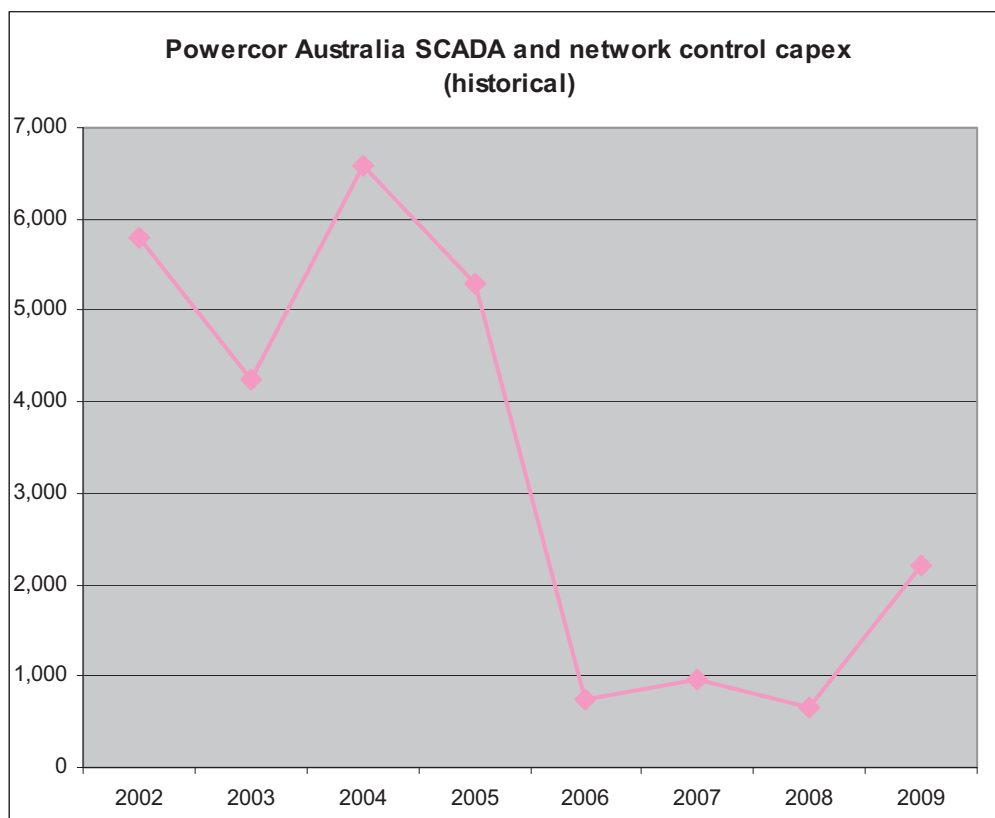
<sup>817</sup> AER, Draft Determination, p411.

<sup>818</sup> AER, Draft Determination, p411.

<sup>819</sup> AER, Draft Determination, p411.

<sup>820</sup> AER, Draft Determination, pp409-13.

<sup>821</sup> AER, Draft Determination, p409.



**Figure 9.3 Powercor Australia's historical SCADA and network control capex**

While the AER found that Victorian DNSPs underspent in relation to the ESCV's benchmark allowance for the current regulatory control period,<sup>822</sup> this is not the case for Powercor Australia. Based on the AER's analysis, Powercor Australia only underspent (relative to the ESCV allowance) by around 8.5 per cent. This is not a significant degree of underspend (particularly in light of the deferrals discussed further below).

In assessing its proposed SCADA and network control capex, the AER did not consider the circumstances and risks facing Powercor Australia in the next regulatory control period. Powercor Australia 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<sup>823</sup> (and the associated HV Protection Sub-Code<sup>824</sup>), Chapter 5 of the Rules<sup>825</sup> and the Distribution Code (consistent with clause 6.5.7(a)(2) of the Rules).

<sup>822</sup> AER, Draft Determination, p410.

<sup>823</sup> Attachment 167 to this Revised Regulatory Proposal.

<sup>824</sup> Attachment 166 to this Revised Regulatory Proposal.

<sup>825</sup> Powercor Australia notes that it is required to comply with Chapter 5 of the Rules from 1 January 2011.

These risks are discussed in relation to Powercor Australia'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 Powercor Australia'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 covered by non-network – IT capex.<sup>826</sup> 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 Powercor Australia's non-network - IT capex. The DMS is designed to support and extend Powercor Australia'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 Powercor Australia 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. As outlined by in Powercor Australia's Response to the AER's Capex Guidance Paper,<sup>827</sup> the deferral of much of Powercor Australia's SCADA and network control capex in the current regulatory control period was for reasons other than efficiency.

For example, prior to preparing its 2006-10 forecasts, Powercor Australia was advised by Telstra that Telstra would retire its TMR network.<sup>828</sup> On the basis of that information, Powercor Australia proposed to upgrade approximately 300 TMR sites to general packet radio system communications. Subsequently, however, Telstra decided that it would refresh, rather than retire, its TMR network. Accordingly, Powercor Australia decided to hold off on the plans to upgrade its TMR sites until a clear business direction was established for its communications infrastructure. This direction was established in the Network Protection and Control Communications Strategy 2009-2014 and includes the replacement of TMR.<sup>829</sup>

In addition, 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:

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<sup>826</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p211.

<sup>827</sup> Powercor Australia, Powercor Australia's Response to the AER's Capex Guidance Paper, 11 January 2010, pp8-9.

<sup>828</sup> This detail was provided to the AER in Powercor Australia's Response to the AER's Capex Guidance Paper, 11 January 2010, p8.

<sup>829</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), p9.

- 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 Powercor Australia's CIC meeting on 1 June 2010 demonstrate that Powercor Australia continues to support the Network Protection and Control Communications Strategy 2009-2014.<sup>830</sup>

*'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.'*

Powercor Australia maintains that each of its proposed projects link with the Network Protection and Control Communications Strategy 2009-2014.<sup>831</sup> This is shown in the material program templates for each of the relevant programs.<sup>832</sup> The linkages are also discussed in Table 9.13 below.

#### **9.11.3.4 SCADA and network control programs proposed by Powercor Australia**

As shown in Table 9.13 below, the programs proposed by Powercor Australia for the next regulatory control period justify forecast expenditure greater than the historical trend.

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<sup>830</sup> Powercor Australia, Minutes to the Capital Investment Committee meeting, 1 June 2010 (Attachment 168 to this Revised Regulatory Proposal), p2.

<sup>831</sup> Attachment P0030 to the Initial Regulatory Proposal.

<sup>832</sup> 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.

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Program	Explanation and link to Network Protection and Control Communications Strategy 2009-2014
Installation of DMS field devices	<p>Refer <b>Executive Summary</b> and <b>section 4</b> of the Network Protection and Control Communications Strategy 2009-2014.<sup>833</sup></p> <p>Installation of DMS field devices (coupled with the DMS) will allow network events to be modelled so that Powercor Australia 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.</p> <p>Powercor Australia'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 allow Powercor Australia to have full control and knowledge of the distribution network, allowing Powercor Australia to avoid any increases in potential health and safety incidents.</p> <p>If the AER's Draft Determination was affirmed, however, Powercor Australia 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.</p>
Migration of automatic circuit reclosers and HV switch control from TMR View to SCADA <sup>834</sup>	<p>Refer to <b>section 4(a)iii</b> of the Network Protection and Control Communications Strategy 2009-2014.<sup>835</sup></p> <p>This program involves the migration of TMR View to SCADA.</p> <p>Powercor Australia has an extensive number of remote controlled ACR's and switches in the distribution network that utilise a proprietary SCADA platform and communication protocol that are now approaching obsolescence. The existing SCADA platform (TMRView) restricts the opportunities that Powercor Australia's key SCADA and DMS platforms can offer in the way of real time information, outage reporting and management and long term historical data. Given the obsolescence of the technology, replacement modems are becoming unavailable.</p> <p>The benefits of migration from TMR View to SCADA include:</p> <ul style="list-style-type: none"> <li>• real time data on SCADA/DMS for improved operational control;</li> <li>• improved operational planning;</li> <li>• improved reporting into OMS;</li> <li>• better management and visibility in high load scenarios;</li> <li>• historical load data available for planning;</li> <li>• upgraded field equipment will offer improved protection and fault detection facilities;</li> <li>• better management and visibility in high load scenarios;</li> <li>• improved data capture for further analysis;</li> <li>• improved fault analysis; and</li> <li>• integration with Powercor Australia's asset management systems.</li> </ul> <p>The work involved in this program is a combination of communication upgrades and field equipment upgrades. The communication upgrades will allow real time communication in line with the Network Protection and Control Communications Strategy 2009-2014<sup>836</sup> and</p>

<sup>833</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014 (Attachment P0030 to the Initial Regulatory Proposal), pp5-6.

<sup>834</sup> See material program template 'Automatic reclosers (ACRs) and SW migration from trunk mobile ratio (TMR) View to SCADA' (included in Attachment 157 to this Revised Regulatory Proposal).

<sup>835</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp9-10.

<sup>836</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009 - 2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp9-10 (section 4(a)(iii)).

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Program	Explanation and link to Network Protection and Control Communications Strategy 2009-2014
	<p>the field equipment upgrades target equipment approaching obsolescence that cannot be upgraded to a modern Ethernet based protocol, to allow data exchange with the SCADA and DMS systems.</p> <p>The program will allow Powercor Australia to maintain reliability by replacing TMR equipment, which is approaching the end of its technically useful life. It will ensure Powercor Australia remains compliant with its 'good asset management' obligations in clause 3 of the Distribution Code.</p> <p>Without the proposed program, Powercor Australia would experience decreasing reliability of the TRM system, which would mean that Powercor Australia would be unable to remote switch field switches and thus reduce the reliability of the network. Powercor Australia would also risk non-compliance with clause 3 of the Distribution Code.</p>
Zone substation SCADA communications to DNP3.0 <sup>837</sup>	<p>Refer to <b>section 4(c)</b> of the Network Protection and Control Communications Strategy 2009 - 2014.<sup>838</sup></p> <p>This program involves replacing the existing extensive rural radio network and Telstra lines that utilise VF technology with digital network and DNP3.0 communications.</p> <p>DNP3.0 is a protocol that is standard on most electronic devices and is suited for application on an Ethernet system. DNP3.0 is fully compatible with SCADA and will improve data bandwidth and the ability to secure communications through redundant communications links.</p> <p>Consistent with its Network Protection and Control Communications Strategy 2009-2014,<sup>839</sup> Powercor Australia is proposing to convert all VF networks to digital networks and DNP communications over the next regulatory control period. Unit costs are based on the average contemporary cost of new radio network equipment, including base stations and Ethernet equipment. They also reflect the average contemporary costs of required security devices as well as redundant links, DNP conversions and RTU communication upgrades.</p> <p>This program will allow Powercor Australia to maintain reliability and security of its network by ensuring effective communication with modern digital protection equipment. It will also ensure Powercor Australia maintains the risk of human error incidents. Powercor Australia considers that this program will ensure it remains compliant with its 'good asset management' obligations under clause 3 of the Distribution Code.</p> <p>Without the DNP protocol, Powercor Australia would be unable to effectively communicate with modern digital protection and would face increased risk of human error incidents from delayed and inadequate system data being communicated. Powercor Australia would also risk non-compliance with clause 3 of the Distribution Code.</p>
Installation of IEC61850 communications <sup>840</sup>	<p>Refer to <b>section 4(c)</b> of the Network Protection and Control Communications Strategy 2009-2014.<sup>841</sup></p> <p>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.</p> <p>This program involves Powercor Australia 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</p>

<sup>837</sup> See document titled 'PAL 168 – ZSS SCADA comms migration to DNP3.0' (provided to the AER by email on 9 March 2010).

<sup>838</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009 – 2014, November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp17-9.

<sup>839</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp6, and 17-9 (section 4(c)).

<sup>840</sup> See document titled 'PAL 168 – Installation of IEC61850 communications' (provided to the AER by email on 9 March 2010).

<sup>841</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp17-9.



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Program	Explanation and link to Network Protection and Control Communications Strategy 2009-2014
	<p>network servers that can manage and store the data from the relays for presentation to users.</p> <p>Powercor Australia 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,<sup>842</sup>. Powercor Australia is proposing implementing communications around this new protocol standard and deploying suitable Ethernet systems to ensure back-up capability within the substations..</p> <p>Going forward, the move to IEC61850 will allow Powercor Australia to maintain reliability and security of its network by ensuring effective communication with modern digital protection equipment. It will also ensure Powercor Australia is compliant with its 'good asset management' obligations under clause 3 of the Distribution Code.</p> <p>Without the above prototyping and testing of IEC61850-enabled systems in the next regulatory control period, Powercor Australia would be unable to effectively migrate to IEC 61850 as contemplated in the Network Protection and Control Communications Strategy 2009-2014.</p>
Enhanced zone substation monitoring via SCADA <sup>843</sup>	<p>Refer to <b>section 4(b)iii</b> of the Network Protection and Control Communications Strategy 2009-2014.<sup>844</sup></p> <p>This program involves the upgrade and replacement of existing remote electronic monitoring equipment in Powercor Australia's zone substations with new enhanced functionality devices.</p> <p>New functionality will relate, in particular, to transformers and capacitor banks (which are essential in managing emerging system loading constraints). The new equipment will be compatible with the new SCADA system and its communications hardware, software and protocols.</p> <p>Powercor Australia is proposing to install enhanced monitoring and control systems in 6 substations per annum over the next regulatory control period.</p> <p>The proposed program is important because remote control and monitoring functionality of Powercor Australia's zone substations will improve the visibility of zone substation assets in order to provide better reliability and asset management. This is particularly important given the long distance and travel times in Powercor Australia's distribution area. The collection of data is also required for ongoing asset maintenance management, including population of the GIS and SAP databases.</p> <p>Upgrading the existing equipment aligns with Powercor Australia's goals as documented in the Network Protection and Control Communications Strategy 2009-2014 (Attachment P0030 to the Initial Regulatory Proposal). The benefits of the program include:</p> <ul style="list-style-type: none"> <li>• better voltage management during planned and unplanned switching;</li> <li>• improved quality of supply to customers;</li> <li>• better management and visibility in high load scenarios;</li> <li>• management of the system fault levels;</li> <li>• improved data capture for further analysis;</li> <li>• improved fault analysis; and</li> <li>• integration with Powercor Australia's asset management systems.</li> </ul> <p>This program will enable Powercor Australia to maintain performance of major plants and thus, to ensure security of supply at zone substations is maintained. The program will also</p>

<sup>842</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp6, and 17-9 (section 4(c)).

<sup>843</sup> See document titled 'PAL 168 – Enhanced zone substation monitoring via SCADA' (provided to the AER by email on 9 March 2010).

<sup>844</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, November 2009 (Attachment P0030 to the Initial Regulatory Proposal), p15.

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Program	Explanation and link to Network Protection and Control Communications Strategy 2009-2014
	<p>allow Powercor Australia to avoid increases in risks of plant failure and personnel safety. Without the proposed program, there would be reduced performance of major plants, which would lead to reduced security of supply at zone substations. There would also be increased risks of plant failure and increased safety risks to personnel.</p>
New fibre allowance <sup>845</sup>	<p>Refer to <b>section 4(a)ii</b> of the Network Protection and Control Communications Strategy 2009-2014.<sup>846</sup></p> <p>Powercor Australia is proposing SCADA and network control capex in the next regulatory period to continue to upgrade the communications network to fibre optics to allow for the increased control and monitoring of plant and relays.<sup>847</sup> As noted in the Network Protection and Control Communications Strategy 2009–2014, fibre 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.<sup>848</sup></p> <p>The existing copper supervisory cables use VF technology which is outdated and not compatible 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 prudent and consistent with good industry practice, and is set out in the Network Protection and Control Communications Strategy 2009-2014.<sup>849</sup> The benefits of fibre optics include:</p> <ul style="list-style-type: none"> <li>• enabling the deployment of modern relays when replacing protection schemes;</li> <li>• providing communication bandwidth for modern protocols;</li> <li>• facilitating, through modern equipment, the collection of data from stations;</li> <li>• facilitating, the implementation of security monitoring systems;</li> <li>• providing enhanced SCADA performance and increased data capture; and</li> <li>• enabling field workers to access to corporate networks at stations.</li> </ul> <p>The proposed program will allow Powercor Australia to maintain reliability by ensuring Ethernet communications over optical fibre is suited to modern protection equipment. It will also avoid any increase in possible human error incidents from delayed and inadequate system data being communicated. Powercor Australia considers this program will ensure compliance with its 'good asset management' obligations under the Distribution Code.</p> <p>Without the proposed program, there would be reliability degradation as obsolete communications systems would not be suited to modern protection equipment. There would also be a possible increase in human error incidents from delayed and inadequate system data being communicated. Powercor Australia would risk non-compliance with clause 3 of the Distribution Code.</p>

**Table 9.13 Key SCADA and network control programs included in Powercor Australia's Revised Regulatory Proposal**

While it is difficult to quantify the benefits likely to result from Powercor Australia's proposed SCADA and network control capex in the next regulatory control period, broadly, the benefits can be summarised as follows:

<sup>845</sup> See document titled 'PAL 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).

<sup>846</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), p5.

<sup>847</sup> See material program template 'New fibre allowance' (included in Attachment 157 tot his Revised Regulatory Proposal).

<sup>848</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), p5.

<sup>849</sup> CitiPower and Powercor Australia, Network Protection and Control Communications Strategy 2009-2014, 11 November 2009 (Attachment P0030 to the Initial Regulatory Proposal), pp8-9 (section 4(a)(ii)).

- 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;
- 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 Powercor Australia to maintain reliability and performance of the network and justify the SCADA and network control capex proposed by Powercor Australia in the next regulatory control period.

### **9.11.3.5 Powercor Australia Revised Regulatory Proposal**

The SCADA and network control capex forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 9.14 below.

Expenditure category	\$'000 (real 2010)					
	2011	2012	2013	2014	2015	Total
SCADA and network control	6,959	7,605	7,815	7,684	7,662	<b>37,724</b>

Table 9.14 SCADA and network control capex forecasts included in Powercor Australia's Revised Regulatory Proposal

## **9.12 Non-network capex**

### **9.12.1.1 Powercor Australia's Initial Regulatory Proposal**

The non-network capex included in Powercor Australia's Initial Regulatory Proposal falls into two subcategories:<sup>850</sup>

- 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'.

<sup>850</sup> Initial Regulatory Proposal, pp131-132.

The AMI leveraged projects proposed by Powercor Australia (as joint projects with CitiPower) were the subject of a cost benefit analysis performed by PwC. They were found to give rise to significant benefits across the two businesses.<sup>851</sup>

Powercor Australia set out its approach to forecasting IT capex in its Initial Regulatory Proposal.<sup>852</sup> Powercor Australia provided to the AER material projects templates setting out details of its forecasts in respect of four general IT projects (including the replacement of its CIS), as well as a material projects template in respect of the AMI leveraged projects.<sup>853</sup>

Powercor Australia also provided to the AER CHED Services' IT Strategic Plan 2010 - 2015,<sup>854</sup> together with an independent review of that plan by Gartner Inc.<sup>855</sup> Subsequent to the Initial Regulatory Proposal, Powercor Australia provided additional information relating to general IT capex in Powercor Australia's Response to the AER's Capex Guideline paper.<sup>856</sup> On 26 February 2010, following a meeting with the AER on 10 February 2010, Powercor Australia provided to the AER a written response to its additional queries, including details of Powercor Australia'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.<sup>857</sup>

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 Powercor Australia had underspent relative to the ESCV allowance in the current regulatory control period because it considered it was efficient to do so.<sup>858</sup>

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 Powercor Australia of the replacement of its CIS as a result of the mandated AMI roll-out.<sup>859</sup>

The AER agreed with Nuttall Consulting that Powercor Australia does not have 'agile' IT architecture supporting its business operations and service delivery and that this absence of 'agile' IT environments will hinder Powercor Australia'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

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<sup>851</sup> 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).

<sup>852</sup> Initial Regulatory Proposal, pp133-5.

<sup>853</sup> Initial Regulatory Proposal, pp425-32.

<sup>854</sup> Attachment P0010 to the Initial Regulatory Proposal.

<sup>855</sup> Attachment P0012 to the Initial Regulatory Proposal.

<sup>856</sup> The response was provided to the AER on 11 January 2010.

<sup>857</sup> AER, Draft Determination, p418.

<sup>858</sup> AER, Draft Determination, p420.

<sup>859</sup> AER, Draft Determination, p421.

proposed IT investments would allow them to better respond in future to external events such as the mandated AMI roll-out.<sup>860</sup>

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 Powercor Australia's IT capex forecast for 2011-13 evenly across 2011-15.<sup>861</sup>

#### **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.<sup>862</sup> Nonetheless, the AER did not allow any capex on AMI leveraged projects proposed by any Victorian DNSP.

The AER rejected Powercor Australia'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;<sup>863</sup>
- the AER considered that the S factor scheme provides financial incentives to Powercor Australia to implement projects (such as the AMI leveraged projects) that achieve reliability benefits;<sup>864</sup> 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.<sup>865</sup>

#### **9.12.2.3 Non-network - other**

Regarding the non-network – other capex proposed by Powercor Australia, the AER indicated that Powercor Australia did not provide sufficient information regarding its proposed projects to satisfy the AER that the proposed capex reasonably reflects the capex criteria.<sup>866</sup>

Given it considered that similar issues and cost drivers were raised in support of the capex proposals for the current regulatory control period, the AER purported to allow capex consistent with the historical trend. 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).<sup>867</sup>

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<sup>860</sup> AER, Draft Determination, p421.

<sup>861</sup> AER, Draft Determination, p422.

<sup>862</sup> AER, Draft Determination, p423.

<sup>863</sup> AER, Draft Determination, p423.

<sup>864</sup> AER, Draft Determination, p423.

<sup>865</sup> AER, Draft Determination, p423.

<sup>866</sup> AER, Draft Determination, p432.

<sup>867</sup> AER, Draft Determination, p429.

While the AER purported to allow capex consistent with historical spend, in fact, in respect of non-network – other capex, the AER provided Powercor Australia with capex significantly below actual historic spend.

### **9.12.3 Powercor Australia's response to the AER's Draft Determination**

#### **9.12.3.1 Summary**

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

Powercor Australia'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. Powercor Australia does not consider that an event such as the AMI roll-out will occur in the next regulatory control period such that Powercor Australia's non-network – IT capex should be constrained to the levels of its actual expenditure in the current regulatory control period. Powercor Australia 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 Powercor Australia 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, Powercor Australia has removed one of the components from the AMI leveraged project that is able to be recovered through the S-factor scheme. Powercor Australia also rejects the AER's proposition that reinforcement capex deferrals would contribute to the funding of AMI leveraged projects.

In addition, Powercor Australia maintains that its proposed non-network – other capex forecasts reasonably reflect the capex criteria. The AER allowed an amount for non-network – other capex that is well below actual historic spend. The AER's allowance cannot reasonably reflect the capex criteria.

For the reasons outlined in the 'General issues' section above, Powercor Australia considers that the AER should use 2009 actual data in its trend analysis. Powercor Australia notes that, as demonstrated by Figures 9.4 and 9.5 below, when 2009 actual data is incorporated into the analysis, the AER's conclusion that Powercor Australia's actual non-network capex follows a gradually increasing trend is less compelling.



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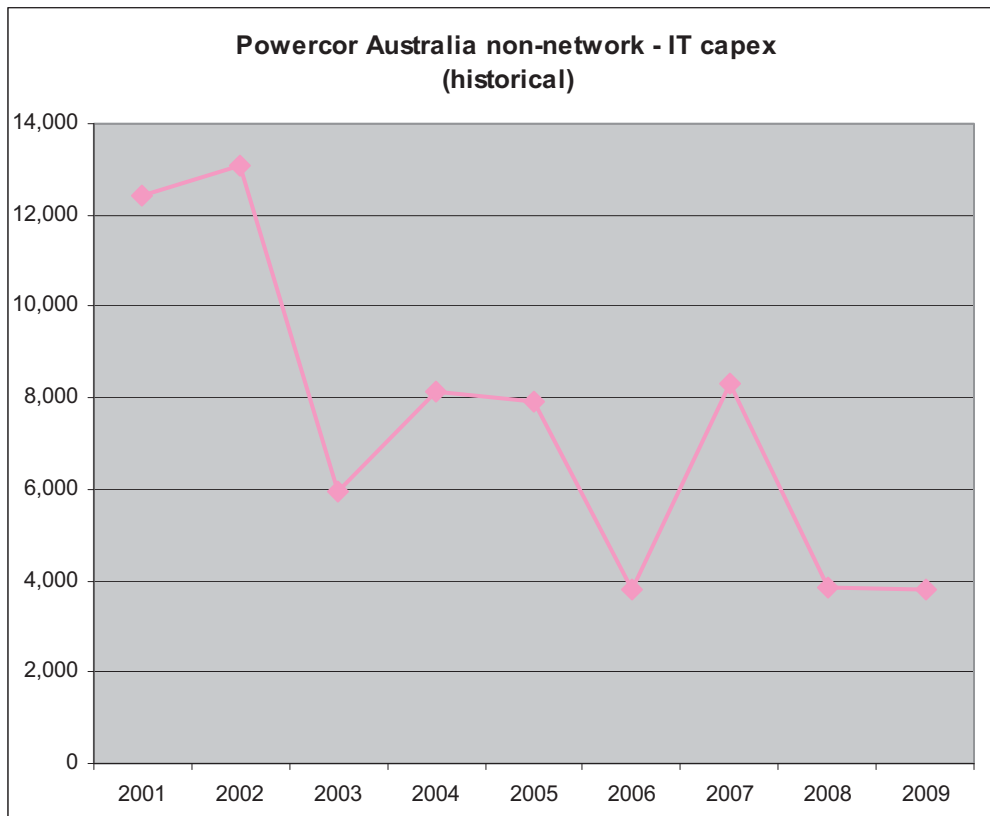


Figure 9.4 Powercor Australia's historical non-network - IT capex

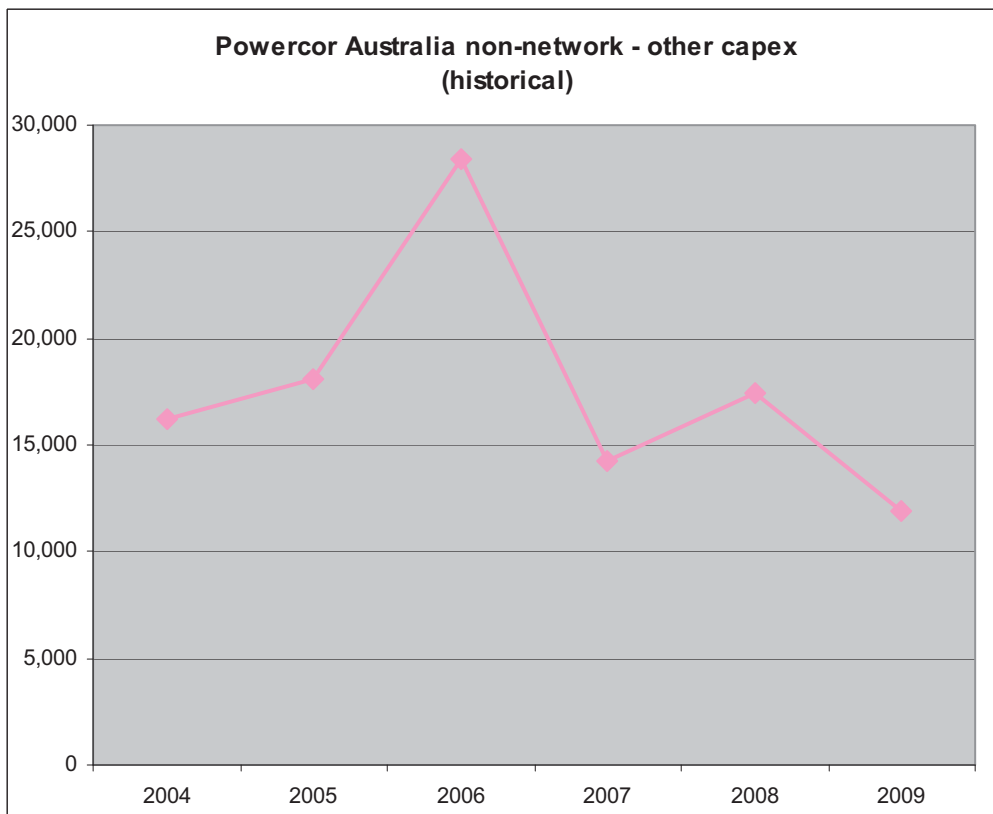


Figure 9.5 Powercor Australia's historical non-network - other capex

### **9.12.3.2 Non-network – IT (general)**

Contrary to the AER's suggestion that Powercor Australia underspent on IT (relative to the ESCV allowance) in the current regulatory control period because it was efficient to do so, Powercor Australia reiterates that Powercor Australia 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 Powercor Australia'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'*.<sup>868</sup> 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 Powercor Australia's proposed general IT projects for the 2011-15 period are likely to be similarly constrained in this period; and
- the asserted lack of 'agility' of the Victorian DNSPs' IT architecture supporting its business operations and service delivery will hinder Powercor Australia's ability to complete its proposed IT projects in the next regulatory control period.

As noted above, Powercor Australia 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.<sup>869</sup> However, Powercor Australia 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 Powercor Australia'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 Powercor Australia'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

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<sup>868</sup> AER, Draft Determination, p422.

<sup>869</sup> 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 Powercor Australia's IT capabilities or its ability to accommodate IT change.

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 Powercor Australia 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'*. Powercor Australia maintains that there is little possibility of such a future event.

Powercor Australia 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.<sup>870</sup> As a result, Nuttall Consulting's findings are gross generalisations and do not take into account the specific circumstances of Powercor Australia.

In discussing the concept of agility in its report, Nuttall Consulting provides examples of the kinds of IT infrastructure it considers to be 'agile'.<sup>871</sup> A number of these technology approaches are already within use across Powercor Australia's business. Powercor Australia has, for instance (as Nuttall Consulting recognises in its report), used Server Virtualisation since 2004.<sup>872</sup> Server Virtualisation delivers each of the attributes described by Nuttall Consulting in its report<sup>873</sup> being high availability, enhanced disaster recovery, portability and live migration.

Further, many systems commonly considered to be 'agile' systems are used by Powercor Australia. For example:

- Powercor Australia has had 'open systems' since 1999;
- it uses commercial 'off the shelf' software rather than customer software; and
- Powercor Australia's IT systems already have identity management to enable many users across multiple systems.

Powercor Australia ensures its systems are agile by using leading technology platform providers. For example, business applications are supplied by SAP, GE Energy and Microsoft. Powercor Australia's DBMS facilities are by Oracle, SQL Server and its infrastructure is by Hitachi Data Systems, Hewlett-Packard, CISCO Systems, Sun and Toshiba. Powercor Australia'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.<sup>874</sup>

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<sup>870</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp74-81.

<sup>871</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, pp78-81.

<sup>872</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p215.

<sup>873</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p79.

<sup>874</sup> More details regarding Powercor Australia's IT service providers are set out in Attachment 173 to this Revised Regulatory Proposal.

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Powercor Australia ensures its systems are agile by using leading technology platform providers.

Powercor Australia 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 CitiPower 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 Powercor Australia 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 Powercor Australia deferring capex because of limitations on its IT capabilities and the amount of IT change that can be accommodated by Powercor Australia,<sup>875</sup> 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 AER on 26 February 2010,<sup>876</sup> 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.

Powercor Australia 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, Powercor Australia 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 Powercor Australia's IT capabilities or its ability to accommodate IT change.

In this regard, Powercor Australia notes that the AER's Draft Determination is inconsistent with the AER's decision to allow capex to ETSA for the CIS.<sup>877</sup> 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.<sup>878</sup> 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

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<sup>875</sup> AER, Draft Determination, p421.

<sup>876</sup> CitiPower and Powercor Australia, Project Proposal CIS Replacement 2013 – 2015, May 2009 (provided to the AER by email on 26 February 2010), slide 3.

<sup>877</sup> AER, South Australian Draft Determination, p171; AER, South Australian Distribution Determination, pp105-6.

<sup>878</sup> 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.

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with CitiPower and Powercor Australia was an efficient way to manage the replacement.<sup>879</sup>

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.<sup>880</sup> 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;
- 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
- Powercor Australia 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 Powercor Australia 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 Powercor Australia'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 Powercor Australia's existing IT infrastructure is not 'agile'. But, in so doing, the AER does not fund Powercor Australia to implement the very IT projects, such as the replacement of the CIS, required if Powercor Australia is to maintain the agility of its IT infrastructure in 2011-15 and beyond.

Powercor Australia 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.<sup>881</sup> Much of Powercor Australia'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

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<sup>879</sup> 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).

<sup>880</sup> AER, Draft Determination, p421.

<sup>881</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p79.

voice and data services and will result in improved customer service, optimise system availability and maximise business efficiency;<sup>882</sup>

- growth and refreshment of SANS, archive backup and de-duplication technology and upgrade system monitoring systems;
- replacing aging TMR technology;
- 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 events such as the mandated AMI roll-out,<sup>883</sup> Powercor Australia 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,<sup>884</sup> clearly set out strategies that have, and will continue to, enable the Powercor Australia 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, Powercor Australia 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, Powercor Australia'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 Powercor Australia's disaster recovery programs. Table 9.15 below demonstrates the growth in IT infrastructure since 2003, thus demonstrating the need for continued growth in IT infrastructure.

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<sup>882</sup> Initial Regulatory Proposal, p426.

<sup>883</sup> AER, Draft Determination, p421.

<sup>884</sup> Attachment P0010 to the Initial Regulatory Proposal.



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	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 9.15 Growth in CitiPower and Powercor Australia's IT infrastructure**

Powercor Australia 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 Powercor Australia 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.<sup>885</sup> Powercor Australia 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.

### **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 Powercor Australia 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.<sup>886</sup> 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, Powercor Australia cannot recover its costs for the AMI leveraged projects through the S factor scheme. Powercor Australia acknowledges that **one** of the AMI leveraged projects (specifically, automatic outage notification) may generate a STPIS saving. Powercor Australia has therefore removed this particular project in preparing its capex forecasts in this Revised Regulatory Proposal. Powercor Australia 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 \$61,505,000.<sup>887</sup> The costs of the

<sup>885</sup> AER, Draft Determination, p419.

<sup>886</sup> 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).

<sup>887</sup> 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.

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remaining AMI leveraged projects proposed by Powercor Australia (set out in Table 9.16 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 – proactive voltage compliant analysis	Utilising the AMI meters' Quality of Supply (QoS) recording to allow improved analysis, network management and customer service. This will allow the businesses to adequately monitor quality of supply compliance.	None. Quality of supply 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 9.16 AMI leveraged projects proposed by Powercor Australia**

Powercor Australia 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.<sup>888</sup> 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 Powercor Australia obtaining any share of those benefits that could be directed towards (partially) funding the AMI leveraged projects.

#### **9.12.3.4 Non-network – other**

In the Draft Determination the AER adopted an inconsistent approach in assessing non-network - other capex compared to network - related capex.

In respect of network - related capex, the AER concluded that the recent historic network capex levels were reflective of the prudent and efficient management of the asset base<sup>889</sup>. By contrast, for non-network - other capex, the AER provided Powercor Australia with capex significantly **below** actual historic spend.

The AER provided Powercor Australia with non-network - other capex totalling \$40 million (\$2010) for the next regulatory control period. However, Powercor Australia's actual historic non-network - other capex spend for 2005-2009 was \$90 million (\$2010) in total. Accordingly, in fact for non-network - other capex, the AER provided Powercor Australia with capex that was \$50 million (\$2010) below actual historic spend.

This decision is contrary to the AER's statement in the Draft Determination that:<sup>890</sup>

*'Given that similar issues and cost drivers were raised in support of the capex proposals for the current and previous regulatory control periods, the AER considers that the actual/out-turn expenditure represents the efficient capex amount'.*

The AER rejected Powercor Australia's proposed non-network - other capex on the grounds that Powercor Australia:<sup>891</sup>

- had not adequately demonstrated how engineering judgements had been translated into a step change in expenditure;
- had not demonstrated an underlying need for a step increase in investment supported by an economic justification; and

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<sup>888</sup> 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).

<sup>889</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p29.

<sup>890</sup> AER, Draft Determination, p430.

<sup>891</sup> AER, Draft Determination, p432.

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- had not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices as achieved in the current period.

Powercor Australia provides the following response to the AER's points:

- It is unclear how engineering judgement is a factor in determining a step change in expenditure for non-network other capex considering this category captures projects of a non-engineering nature.
- The majority of non-network other capex relates to ongoing non-operational activities such as motor vehicles, general equipment, office furniture etc, which is required to support management and operation of the network in accordance with good electricity practice. By their very nature, it is difficult to apply a separate cost-benefit analysis for every chair and vehicle. Accordingly, Powercor Australia has demonstrated for discrete projects such as the replacement of mobile cranes the need for the investment.
- In circumstances where the AER's approved expenditure is substantially less than the historic direct capex spend, Powercor Australia fails to understand the AER's comment that it has not demonstrated why it cannot management existing programs and associated risks within the current level of expenditure, This comment by the AER suggests that (contrary to what the AER has actually done) the AER proposed to at least approve expenditure commensurate with Powercor Australia's current level of expenditure.

Further, as discussed in the 'General issues' section above, Powercor Australia considers that, in forecasting the non-network – other capex required in the next regulatory control period by reference to historical capex, the AER should include 2009 actual data. Accordingly, Powercor Australia maintains that the AER should accept its proposed non-network – other capex forecasts as reasonably reflecting the capex criteria

#### **9.12.4 Powercor Australia's Revised Regulatory Proposal**

The non-network capex forecasts included in Powercor Australia's Revised Regulatory Proposal are set out in Table 9.17 below.

	\$'000 (real 2010)					
	2011	2012	2013	2014	2015	Total
Non-Network Assets - IT	26,496	23,136	21,010	32,885	26,337	<b>129,864</b>
Non-Network Assets - Other	17,143	18,291	17,381	17,535	17,505	<b>87,855</b>
<b>Non-Network Assets - Total</b>	<b>43,639</b>	<b>41,427</b>	<b>38,391</b>	<b>50,420</b>	<b>43,842</b>	<b>217,719</b>

Table 9.17 Non-network capex forecasts included in Powercor Australia's Revised Regulatory Proposal

### **9.13 Powercor Australia's Revised Regulatory Proposal**

The total forecast capex included in Powercor Australia's Revised Regulatory Proposal is set out in Table 9.18. The key assumptions which underlie the proposed capex as set out and included in Powercor Australia's building block proposal are listed in Appendix 1.1 to this Revised Regulatory Proposal.

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	\$'000 (real 2010)					
	2011	2012	2013	2014	2015	Total
Reinforcement	55,783	57,783	63,740	65,198	71,173	313,678
Gross new customer connections	141,298	144,460	147,090	148,956	150,651	732,456
<b>Sub-total demand related</b>	<b>197,082</b>	<b>202,243</b>	<b>210,831</b>	<b>214,154</b>	<b>221,824</b>	<b>1,046,134</b>
Reliability and quality maintained	91,052	100,364	99,862	94,776	95,777	481,831
Environmental, safety and legal	8,211	8,352	8,456	8,527	8,595	42,141
SCADA/Network Control	6,959	7,605	7,815	7,684	7,662	37,724
<b>Sub-total network</b>	<b>303,303</b>	<b>318,564</b>	<b>326,964</b>	<b>325,141</b>	<b>333,858</b>	<b>1,607,830</b>
Non-network - IT	26,496	23,136	21,010	32,885	26,337	129,864
Non-network - other	17,143	18,291	17,381	17,535	17,505	87,855
<b>Sub-total non-network</b>	<b>43,639</b>	<b>41,427</b>	<b>38,391</b>	<b>50,420</b>	<b>43,842</b>	<b>217,719</b>
<b>Total gross capex</b>	<b>346,942</b>	<b>359,991</b>	<b>365,355</b>	<b>375,560</b>	<b>377,701</b>	<b>1,825,549</b>
Less capital contributions	42,190	43,248	44,062	44,582	45,124	219,205
<b>Total</b>	<b>304,753</b>	<b>316,743</b>	<b>321,293</b>	<b>330,979</b>	<b>332,577</b>	<b>1,606,344</b>

Table 9.18 Total forecast capex included in Powercor Australia's Revised Regulatory Proposal

## 10. OPENING ASSET BASE

In this Chapter of the Revised Regulatory Proposal, Powercor Australia responds to Chapter 9 of the Draft Determination regarding Powercor Australia's opening asset base.

### 10.1 Summary of key points

Powercor Australia 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. Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal

Powercor Australia 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.<sup>892</sup>

Table 10.1 shows the roll forward of Powercor Australia's RAB to 31 December 2010 as set out in the Initial Regulatory Proposal.<sup>893</sup>

	\$m (nominal)				
	2006	2007	2008	2009	2010
Opening RAB	1,651.5	1,756.7	1,879.6	1,970.2	2,116.9
Net capital expenditure	166.9	167.7	173.7	171.9	199.1
Disposals	4.9	2.3	3.0	-	-
Depreciation	106.7	111.6	115.1	123.4	126.1
Indexation of RAB	50.0	69.2	35.0	98.1	26.7
Closing RAB	1,756.7	1,879.6	1,970.2	2,116.9	2,216.6

**Table 10.1 Initial Regulatory Proposal - Roll forward of the RAB from 1 January 2006 to 31 December 2010**

<sup>892</sup> Roll Forward Model (Attachment 3 to the Initial Regulatory Proposal).

<sup>893</sup> Initial Regulatory Proposal, p302.



## 10.4 AER's Draft Determination

The AER's decision on Powercor Australia's opening RAB in the Draft Determination is set out in Table 10.2.<sup>894</sup>

	\$m (2010)				
	2006	2007	2008	2009	2010
Opening RAB	1,916.8	1,978.7	2,034.4	2,093.0	2,136.2
Net capex	182.0	176.5	181.0	168.2	199.1
Depreciation	-120.1	-120.9	-122.4	-124.9	-126.9
Compound return on 2005 capex difference					-4.3
Closing RAB	1,978.7	2,034.4	2,093.0	2,136.2	2,204.9
Difference from proposed RAB					-11.7

**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 Powercor Australia proposed applying the book value of disposals.<sup>895</sup>

In calculating the roll forward of the RAB from 1 January 2011 to 31 December 2015, the AER has accepted Powercor Australia's forecast in its Initial Regulatory Proposal of zero disposals over the period.

## 10.5 Powercor Australia's response to the AER's Draft Determination

Powercor Australia 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. Powercor Australia 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

<sup>894</sup> AER, Draft Determination, p455.

<sup>895</sup> AER, Draft Determination, p444.

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power to make adjustments for 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.

Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia 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. Powercor Australia considers that no adjustment should be made to account for the difference between estimated and actual disposals in 2005.

Powercor Australia's calculation of the opening RAB is set out in Table 10.3.

	\$m (nominal)				
	2006	2007	2008	2009	2010
Opening RAB	1,654.3	1,759.3	1,880.0	1,970.2	2,110.9
Net capex	166.9	167.7	173.7	167.0	207.2
Disposals	5.2	4.6	3.5	1.0	-
Depreciation	106.7	111.6	115.1	123.4	126.1
Indexation of RAB	50.1	69.3	35.0	98.1	26.6
Closing RAB	1,759.3	1,880.0	1,970.2	2,110.9	2,218.6

**Table 10.3 Roll forward of the RAB from 1 January 2006 to 31 December 2010**

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Powercor Australia'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	2,214.7	2,476.9	2,751.8	3,032.1	3,323.8
Net capex	324.4	345.6	359.5	379.9	391.5
Disposals	-	-	-	-	-
Depreciation	119.1	134.3	150.0	166.1	185.2
Indexation of RAB	56.9	63.7	70.7	77.9	85.4
Closing RAB	2,476.9	2,751.8	3,032.1	3,323.8	3,615.6

**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, Powercor Australia responds to Chapter 10 of the Draft Determination regarding depreciation.

### **11.1 Summary of key points**

Powercor Australia 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 Powercor Australia'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 Powercor Australia's Initial Regulatory Proposal

In its Initial Regulatory Proposal, Powercor Australia 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:<sup>896</sup>

	\$m (nominal)					
	2011	2012	2013	2014	2015	Total
<b>Depreciation</b>	64.3	72.7	81.2	90.3	101.5	410.0

Table 11.1 Initial Regulatory Proposal - Depreciation

This depreciation calculation was based on the following proposed asset lives:<sup>897</sup>

	Standard	Remaining
Subtransmission	50.0	25.8
Distribution system assets	51.0	25.5
Metering	15.0	5.8
Public lighting	25.0	14.1
SCADA/Network control	13.0	6.4
Non-network - IT	6.0	5.2
Non-network - Other	15.0	9.7

Table 11.2 Initial Regulatory Proposal - Asset lives (years)

### 11.4 AER's Draft Determination

In the Draft Determination, the AER determined that Powercor Australia's depreciation for each regulatory year should be as follows:<sup>898</sup>

	\$m (nominal)					
	2011	2012	2013	2014	2015	Total
<b>Depreciation</b>	62.0	68.1	74.6	81.5	88.9	375.1

Table 1.3 Draft Determination - Depreciation

<sup>896</sup> Powercor Australia, Post Tax Revenue Model (Attachment 2 to this Revised Regulatory Proposal).

<sup>897</sup> Initial Regulatory Proposal, p298.

<sup>898</sup> AER, Draft Determination, p477.

This depreciation calculation was based on the following asset lives:<sup>899</sup>

	2011-15 standard asset lives for new capex	2011-15 remaining asset lives
Subtransmission	50.0	25.8
Distribution system assets	51.0	25.7
Metering	N/A	5.8
Public lighting	N/A	13.1
SCADA/Network control	13.0	6.3
Non-network - IT	6.0	5.2
Non-network - Other	15.0	9.7
Equity raising costs	45.2	N/A

Table 11.4 Draft Determination - Asset lives (years)

## 11.5 Powercor Australia's response to the AER's Draft Determination

Powercor Australia accepts the AER's calculation of depreciation and asset lives set out in the Draft Determination, except that Powercor Australia considers that minor amendments and corrections are required to the AER's calculations. Powercor Australia's proposed amendments are set out in the change log to Powercor Australia's Roll Forward Model.

## 11.6 Powercor Australia's Revised Regulatory Proposal

Powercor Australia 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
<b>Depreciation</b>	62.2	70.6	79.3	88.1	99.8	400

Table 11.5 Revised Regulatory Proposal - Depreciation

The calculation of these amounts is set out in Powercor Australia's revised Post Tax Revenue Model, Roll Forward Model and Remaining Asset Life Model.

<sup>899</sup> AER, Draft Determination, p470.



## **12. COST OF CAPITAL**

In this Chapter of the Revised Regulatory Proposal, Powercor Australia 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**

Powercor Australia 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. Powercor Australia 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.

Powercor Australia proposes an alternative method developed by PwC for testing whether CBASpectrum or Bloomberg produces the more accurate estimate of the DRP. Powercor Australia 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.

Powercor Australia 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. Powercor Australia proposes an alternative method for extrapolating the Bloomberg curve developed by PwC.

Based on Powercor Australia'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, Powercor Australia considers that the appropriate DRP is 4.28 per cent for the averaging period used for this Revised Regulatory Proposal.

Powercor Australia 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 Powercor Australia's proposed approach for determining the DRP, then Powercor Australia 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 Powercor Australia does not agree with the analysis underlying the AER's decision regarding the MRP in the Draft Determination, Powercor Australia adopts the MRP of 6.5 per cent set out in the Draft Determination.

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### 12.1.3 Summary and other parameters

The following table sets out the values for the WACC parameters that were proposed by Powercor Australia in its Initial Regulatory Proposal, the values that were adopted by the AER in the Draft Determination, and the values that are proposed by Powercor Australia in this Revised Regulatory Proposal.

Parameter	Initial Regulatory Proposal	Draft Determination	Revised Regulatory Proposal	Does Powercor Australia 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 ( $\beta_e$ )	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
<b>Nominal WACC</b>	<b>10.86%</b>	<b>9.68%</b>	<b>10.29%</b>	-

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+;<sup>900</sup> and

<sup>900</sup> AER, SoRI (Attachment 174 to this Revised Regulatory Proposal).

- 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.<sup>901</sup>

### **12.2.2 Powercor Australia's Initial Regulatory Proposal**

Powercor Australia 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.<sup>902</sup>

Powercor Australia's method for determining the DRP was based on a report from PwC, which was attached to the Initial Regulatory Proposal.<sup>903</sup> 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, Powercor Australia 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.

Powercor Australia'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.<sup>904</sup>

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.<sup>905</sup> 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.

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;

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<sup>901</sup> AER, SoRI (Attachment 174 to this Revised Regulatory Proposal), p7.

<sup>902</sup> Initial Regulatory Proposal, p307.

<sup>903</sup> PwC, Victorian Distribution Businesses Methodology to Estimate the Debt Risk Premium, November 2009 (Attachment P0079 to Initial Regulatory Proposal).

<sup>904</sup> Initial Regulatory Proposal, p307.

<sup>905</sup> AER, Draft Determination, p523.

- 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.<sup>906</sup>

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 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia does not accept the AER's method for determining whether Bloomberg or CBASpectrum should be used to determine the DRP. Powercor Australia 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.

Powercor Australia 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.

Powercor Australia 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).<sup>907</sup> Powercor Australia 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 Powercor Australia's proposed approach and continues to apply the framework set out in its Draft Determination, then Powercor Australia 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 Powercor Australia's proposed method for testing Bloomberg and CBASpectrum**

Powercor Australia 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).

Powercor Australia 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:<sup>908</sup>

- test the integrity of the fair value curves to the extent possible;

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<sup>906</sup> AER, Draft Determination, pp522-523.

<sup>907</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).

<sup>908</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), pp3-4.

- 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:<sup>909</sup>

*'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:<sup>910</sup>

- 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 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.

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<sup>909</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), p2.

<sup>910</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), pp5-7.

- 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, Powercor Australia 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 Powercor Australia'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.<sup>911</sup>

Powercor Australia considers that extrapolation of the Bloomberg curve should be performed by using the methodology set out in the attached report from PwC,<sup>912</sup> 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:<sup>913</sup>

- 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 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.

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<sup>911</sup> AER, Draft Determination, p521.

<sup>912</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).

<sup>913</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal), pp22-23.



#### **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'.<sup>914</sup> 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:<sup>915</sup>

*'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

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<sup>914</sup> 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).

<sup>915</sup> 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'.<sup>916</sup> 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.

Powercor Australia 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 Powercor Australia's proposed approach and continues to apply the framework set out in its Draft Determination, Powercor Australia 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:<sup>917</sup>

*'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:<sup>918</sup>

*'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 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia 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.
- 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

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<sup>916</sup> CEG, Detailed application of AER cost of debt methodology to alternative bond samples, A report for Victorian DBs, July 2010 (Attachment 257 to this Revised Regulatory Proposal).

<sup>917</sup> AER, Draft Determination, p520.

<sup>918</sup> *Application by Energy Australia and Others* [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at 122.

Powercor Australia's proposed method set out in section 12.2.4.1 above and the attached expert report from PwC.<sup>919</sup>

- 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 Powercor Australia'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 Powercor Australia's proposed method and a measurement period of the 30 business days from 19 April to 31 May 2010, Powercor Australia 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 Powercor Australia'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.<sup>920</sup>

## **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.<sup>921</sup>

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

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<sup>919</sup> PwC, Methodology for the calculation of debt risk premium, 19 July 2010 (Attachment 162 to this Revised Regulatory Proposal).

<sup>920</sup> 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).

<sup>921</sup> 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 Powercor Australia's Initial Regulatory Proposal**

Powercor Australia proposed an MRP of 8.0 per cent in its Initial Regulatory Proposal.<sup>922</sup> 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 Officer<sup>923</sup>; and
- Powercor Australia'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.<sup>924</sup>

### **12.3.3 AER's Draft Determination**

In the Draft Determination, the AER adopted an MRP of 6.5 per cent.<sup>925</sup> 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.<sup>926</sup>

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<sup>922</sup> Initial Regulatory Proposal, p312.

<sup>923</sup> Professor Bob Officer and Dr Stephen Bishop of Value Adviser Associates, Market Risk Premium Estimate for 2011 to 2015, October 2009 (Attachment P0194 to the Initial Regulatory Proposal).

<sup>924</sup> Initial Regulatory Proposal, pp307-312.

<sup>925</sup> AER, Draft Determination, p503.

<sup>926</sup> AER, Draft Determination, p503.

#### **12.3.4 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia 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.

Powercor Australia 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.<sup>927</sup>

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'<sup>928</sup> 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:<sup>929</sup>

*'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:<sup>930</sup>

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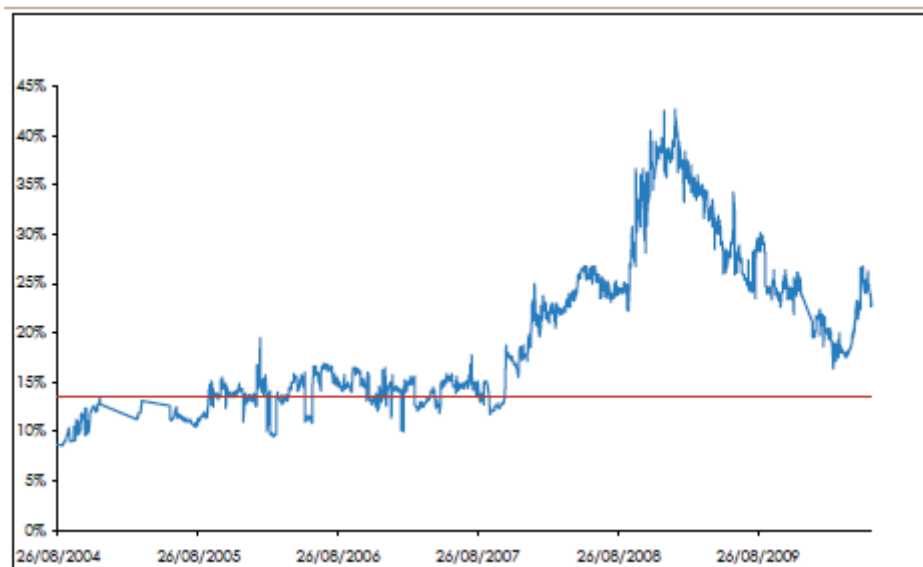
<sup>927</sup> See for example the graphs on pp501-503 of the Draft Determination.

<sup>928</sup> 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).

<sup>929</sup> 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.

<sup>930</sup> 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:<sup>931</sup>

*'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.<sup>932</sup> 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.<sup>933</sup>

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.<sup>934</sup>

<sup>931</sup> 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.

<sup>932</sup> 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.

<sup>933</sup> 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.

<sup>934</sup> 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:<sup>935</sup>

*'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**

Powercor Australia 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.<sup>936</sup> 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*.<sup>937</sup> In that decision, the Tribunal stated:<sup>938</sup>

*'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.

Powercor Australia 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:<sup>939</sup>

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<sup>935</sup> 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.

<sup>936</sup> AER, Draft Determination, p490.

<sup>937</sup> [2010] ACompT 1 (Attachment 179 to this Revised Regulatory Proposal).

<sup>938</sup> [2010] ACompT 1 (Attachment 179 to this Revised Regulatory Proposal) at [419] and [422].

*'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, Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

Despite continuing to consider that the most appropriate MRP is 8.0 per cent, Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal:

- nominal risk-free rate;<sup>940</sup>
- expected inflation rate;<sup>941</sup>
- gearing level (value of equity as a proportion of the value of equity and debt);<sup>942</sup> and
- equity beta.<sup>943</sup>

Powercor Australia does not make any amendments to its Initial Regulatory Proposal in relation to these parameters.

Powercor Australia 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.

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.

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<sup>939</sup> 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).

<sup>940</sup> AER, Draft Determination, p488. This indicative rate was measured over the 15 days ending on 19 March 2010.

<sup>941</sup> AER, Draft Determination, p525.

<sup>942</sup> AER, Draft Determination, p485.

<sup>943</sup> AER, Draft Determination, p505.

## **12.5 Regulatory Information Notice response**

Paragraphs 2.3 and 2.4 of the Further RIN require Powercor Australia 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.

Powercor Australia 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, Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal, but was addressed in the estimated corporate income tax Chapter of the Draft Determination.

### **13.1 Summary of key points**

Powercor Australia does not accept the AER's decision in the Draft Determination to adopt a value of 0.65 for gamma.

Powercor Australia 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. Powercor Australia considers that the appropriate value for gamma is 0.5.

Powercor Australia 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:

$$ETC = (ETI \times r)(1 - \gamma)$$

where:

ETI is the estimated taxable income for the regulatory year;

r is the statutory income tax rate; and

$\gamma$  (gamma) is the assumed utilisation of imputation credits.

Gamma is conventionally estimated using the Monkhouse formulation, under which gamma is the product of:<sup>944</sup>

- 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.

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

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<sup>944</sup> 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.

DNSPs or specified classes of DNSPs.<sup>945</sup> 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'*.<sup>946</sup> In determining whether a departure from a SoRI is justified in a distribution determination, the AER is required to consider:<sup>947</sup>

- 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.<sup>948</sup> In the SoRI Final Decision, the AER justified this on the grounds that:<sup>949</sup>

- 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:<sup>950</sup>
  - providing a service provider with a reasonable opportunity to recover at least the efficient costs;

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<sup>945</sup> Rules, clause 6.5.4.

<sup>946</sup> Rules, clause 6.5.4(g).

<sup>947</sup> Rules, clause 6.5.4(h).

<sup>948</sup> AER, SoRI (Attachment 174 to the Revised Regulatory Proposal).

<sup>949</sup> AER, SoRI Final Decision, p466. (Attachment 175 to the Revised Regulatory Proposal).

<sup>950</sup> AER, Draft Determination, pp529-530.



- 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.<sup>951</sup>

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.<sup>952</sup>

### **13.2.2 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia proposed a departure from the value of gamma set in the SoRI, as did all of the other Victorian DNSPs. Powercor Australia and all of the other DNSPs except Jemena proposed a value of 0.5,<sup>953</sup> while Jemena proposed a value of 0.2.<sup>954</sup>

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<sup>955</sup> (architect of the CAPM Officer Framework) and tax lawyer Peter Feros<sup>956</sup> 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.<sup>957</sup> Jemena further noted the conclusions of a tax study prepared for Jemena by Synergies,<sup>958</sup> which found that between 2003-07 the payout ratio averaged 66 per cent, based on tax statistics.<sup>959</sup>

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

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<sup>951</sup> AER, SoRI Final Decision (Attachment 175 to this Revised Regulatory Proposal), p395.

<sup>952</sup> 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.

<sup>953</sup> Initial Regulatory Proposal, p315.

<sup>954</sup> Jemena, Regulatory Proposal 2011-2015, 30 November 2009, p175.

<sup>955</sup> 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).

<sup>956</sup> Peter Feros, Review of WACC parameters: Gamma, ETSA Price Reset, 22 June 2009 (Attachment 182 to the Revised Regulatory Proposal).

<sup>957</sup> 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)**).

<sup>958</sup> Synergies Economic Consulting, Gamma: New Analysis Using Tax Statistics, 28 May 2009.

<sup>959</sup> Jemena, Regulatory Proposal 2011-15, 30 November 2009, p178.

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:<sup>960</sup>

*'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<sup>961</sup> 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**);<sup>962</sup> 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**).<sup>963</sup>

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 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'*.<sup>964</sup>

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

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<sup>960</sup> 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).

<sup>961</sup> Synergies Economic Consulting, Gamma: New Analysis Using Tax Statistics, 28 May 2009.

<sup>962</sup> Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010.

<sup>963</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010.

<sup>964</sup> AER, Draft Determination, p537.

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;<sup>965</sup>
- 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);<sup>966</sup>
- 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 Powercor Australia'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',<sup>967</sup> in line with the findings of Officer and Hathaway (2004) and more recently NERA (2010).<sup>968</sup> 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

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<sup>965</sup> AER, Draft Determination, pp542-545.

<sup>966</sup> AER, Draft Determination, p548.

<sup>967</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p27.

<sup>968</sup> 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 Clevee of CitiPower and Powercor Australia on 22 February 2010) (NERA (2010)) (Attachment 184 to this Revised Regulatory Proposal).

McKenzie and Partington consider to be unrealistic) or undistributed credits have the same value as distributed credits:<sup>969</sup>

*'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:<sup>970</sup>

*'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:<sup>971</sup>

*'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, Powercor Australia 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.<sup>972</sup> 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

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<sup>969</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p26.

<sup>970</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p25.

<sup>971</sup> Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010, p33.

<sup>972</sup> Peter Feros, Review of WACC parameters: Gamma, ETSA Price Reset, 22 June 2009 (Attachment 182 to this Revised Regulatory Proposal).

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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.<sup>973</sup> It would also explain the tendency for franking account balances to rise over time, noted by McKenzie and Partington.<sup>974</sup>

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.<sup>975</sup> 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, Powercor Australia 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.

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.<sup>976</sup> Such simplifying assumptions are common in academic analysis and are not necessarily intended to reflect reality.

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<sup>973</sup> Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010, p36.

<sup>974</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p27.

<sup>975</sup> AER, Draft Decision, p537.

<sup>976</sup> 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).



#### **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):<sup>977</sup>

*'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):<sup>978</sup>

*'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 AER appears to have ignored the limitations of the only tax study it relies on (Handley and Maheswaran (2008)<sup>979</sup>). 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*

Powercor Australia 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

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<sup>977</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, pp9-10.

<sup>978</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p3.

<sup>979</sup> 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)**).



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,<sup>980</sup> 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:<sup>981</sup>

*'...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.

Powercor Australia 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.

*(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'<sup>982</sup> 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-

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<sup>980</sup> Associate Professor John Handley, Report prepared for the AER on the estimation of gamma, 19 March 2010, p15.

<sup>981</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p9.

<sup>982</sup> 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.

point of 0.74.<sup>983</sup> 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.<sup>984</sup> It is not apparent what the basis for this assumption is, besides mere 'investor rationality'.<sup>985</sup> 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.<sup>986</sup> 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 highly unreliable.<sup>987</sup> 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

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<sup>983</sup> 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).

<sup>984</sup> 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).

<sup>985</sup> 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.

<sup>986</sup> Neville Hathaway, Comment on: "A Measure of the Efficacy of the Australian Imputation Tax System" by John Handley and Krishnan Maheswaran, July 2008 (Attachment 190 to this Revised Regulatory Proposal).

<sup>987</sup> Neville Hathaway, Imputation Credit Redemption: ATO data 1988-2008, July 2010 (Attachment 189 to this Revised Regulatory Proposal).

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:<sup>988</sup>

*'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 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.<sup>989</sup>

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

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<sup>988</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p5.

<sup>989</sup> SFG, Response to the AER draft determination in relation to gamma, 13 January 2010 (Attachment 187 to this Revised Regulatory Proposal), pp 17 – 18.

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.<sup>990</sup>

*(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.<sup>991</sup> 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.

McKenzie and Partington stated that the number of zero drop-off observations in the SFG study is 'higher than expected'.<sup>992</sup> 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.<sup>993</sup> 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:<sup>994</sup>

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<sup>990</sup> 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.

<sup>991</sup> See, Christopher L Skeels, Response to AER Questions, 21 September 2009 (Attachment 191 to this Revised Regulatory Proposal), p 6 – 8.

<sup>992</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p38.

<sup>993</sup> Professor Michael McKenzie and Associate Professor Graham Partington, Evidence and submissions on gamma, 25 March 2010, p38.

<sup>994</sup> SFG, Issues relating to the estimation of gamma, 15 July 2010 (Attachment 192 to this Revised Regulatory Proposal), p18.

*'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:<sup>995</sup>

- 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.<sup>996</sup> 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 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.<sup>997</sup>

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<sup>998</sup> and also by the AER's own consultants.

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<sup>995</sup> SFG, Issues relating to the estimation of gamma (Attachment 192 to this Revised Regulatory Proposal), 10 July 2010.

<sup>996</sup> *Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6 (Attachment 193 to this Revised Regulatory Proposal).

<sup>997</sup> AER, Draft Determination, pp551-552.

<sup>998</sup> SFG, Issues relating to the estimation of gamma, 15 July 2010 (Attachment 192 to this Revised Regulatory Proposal), pp25-26.



### **13.2.4.3 Conclusions**

Powercor Australia 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.

### **13.2.5 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia does not make any amendments to its Initial Regulatory Proposal in relation to the value of gamma.

Powercor Australia 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. Powercor Australia 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 Powercor Australia 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.



Powercor Australia proposes departures from the value for gamma set out in the SoRI. As explained in section 13.2.4 above, Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal**

In the Initial Regulatory Proposal, Powercor Australia 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 Powercor Australia'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.<sup>999</sup>

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 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia adopts the AER's amendments in the Draft Determination, except that Powercor Australia 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.<sup>1000</sup>

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<sup>999</sup> AER, Draft Determination, p555.

<sup>1000</sup> 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).

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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.

Powercor Australia 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.<sup>1001</sup> 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 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia 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.

Powercor Australia'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	3.9	4.8	6.0	7.2	9.0

**Table 13.1 Estimated cost of corporate income tax**

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Australian Government Fact Sheet, Cutting the Company Tax Rate (accessed 8 July 2010) (Attachment 194 to this Revised Regulatory Proposal).

<sup>1001</sup> 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, Powercor Australia 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**

Powercor Australia does not accept the AER's decision to deduct Powercor Australia's accrued negative carryover from 2001-05 from Powercor Australia's 2006-10 efficiency carryover amounts. That decision is incorrect and based on errors of law.

- The AER has no power under the Rules to take the 2001-05 negative carryover into account in making its Final Determination.
- The AER's conclusion in the Draft Determination that it is authorised, and indeed required, by the AER's EBSS Final Decision, the ESCV's 2006-10 EDPR and the NEVA to deduct the 2001-05 negative carryover from Powercor Australia's positive carryover amount for 2006-10 is based on several errors of law. In particular:
  - neither the AER's EBSS Final Decision nor the ESCV's 2006-10 EDPR can confer powers on the AER that are not conferred on it under the Rules; and
  - the AER's enforcement powers under the NEVA do not apply.

Powercor Australia does not accept the AER's decision to reject Powercor Australia's proposed adjustments to the 2006-10 carryover amounts to exclude uncontrollable costs (increased vegetation management costs, 2008 ATO costs, superannuation costs and GSL payments) and remove the ESCV's \$5.5 million efficiency adjustment and 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.

Powercor Australia 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.

### **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 2001-05 negative carryover**

### **14.3.1 Powercor Australia's Initial Regulatory Proposal**

Powercor Australia incurred a negative efficiency carryover of -\$22.9 million (in \$2004) in the 2001-05 regulatory period . In the ESCV's 2006-10 EDPR, the ESCV decided not to carry over this amount when applying the ECM in the ESCV's 2006-10 EDPR.

In its Initial Regulatory Proposal, Powercor Australia stated that the NEL, the Rules and the AER's EBSS Guideline do not permit the AER to deduct the 2001-05 negative carryover in its Final Determination for the following reasons:<sup>1002</sup>

- clause 6.4.3(a) of the Rules only allows revenue increments or decrements arising from the application of the EBSS or from the application of a control mechanism in the previous regulatory control period, and that clause does not allow the AER to include revenue decrements based on mechanisms applied in prior periods;
- carrying over 2001-05 losses would be inconsistent with the NEO and revenue and pricing principles in the NEL, in particular the requirement that a DNSP should be provided with effective incentives in order to promote economic efficiency; and
- carrying over 2001-05 losses would be inconsistent with the EBSS principles in clause 6.5.8(c) of the Rules.

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<sup>1002</sup> Initial Regulatory Proposal, pp263-264.

Powercor Australia also noted that neither the AER's EBSS Guideline nor the Framework and Approach Paper addressed the 2001-05 negative carryover or contemplated that it would be taken into account in the Final Determination.

Powercor Australia also provided an expert report from NERA, which stated that it is not appropriate to carry over the 2001-05 negative carryover and that to do so would be inconsistent with the NEO, the revenue and pricing principles and clause 6.5.8(c).<sup>1003</sup>

#### **14.3.2 AER's Draft Determination**

In the Draft Determination, the AER deducted the 2001-05 negative carryover from Powercor Australia's 2006-10 efficiency carryover amounts.<sup>1004</sup>

The AER considered that it must apply the ESCV's ECM as set out in the ESCV's 2006-10 EDPR. The AER disagreed with Powercor Australia's view that the AER has no power to deduct 2001-05 negative carryover from Powercor Australia's positive 2006-10 carryover amounts. Instead, the AER considered that it was empowered to do so, and indeed required to do so, by the ESCV's 2006-10 EDPR, the AER's EBSS Final Decision and the AER's powers under the NEVA to enforce the ESCV's 2006-10 EDPR.<sup>1005</sup>

#### **14.3.3 Powercor Australia's response to the AER's Draft Determination**

The AER's conclusion in the Draft Determination is incorrect and based on errors of law.

In the Draft Determination, the AER states that it is required to bring the 2001-05 negative carryover to account because the AER's EBSS Final Decision states that the AER will apply carryover amounts under existing schemes in accordance with the existing jurisdictional arrangements. That is incorrect and an error of law for the following reasons:

- The AER's own final decision on a matter cannot provide the AER with powers that are not conferred on it under the Rules. As explained below, the AER has no powers under the Rules to address the 2001-05 negative carryover in its Final Determination.
- Deducting the 2001-05 negative carryover would be contrary to the NEO and revenue and pricing principles. The AER's own final decision on a matter cannot empower the AER to act in a manner that is inconsistent with the NEO and revenue and pricing principles.

In the Draft Determination, the AER states that the ECM in the ESCV's 2006-10 EDPR empowers the AER to deduct the 2001-05 negative carryover. That is incorrect and an error of law. The ESCV's 2006-10 EDPR cannot confer any powers on the AER that are not conferred on it under the Rules, and cannot empower the AER to act in a manner that is inconsistent with the NEO and revenue and pricing principles.

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<sup>1003</sup> NERA, Treatment of Accrued Carryovers in the 2011-15 Regulatory Period, 22 December 2009, provided by Powercor Australia 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).

<sup>1004</sup> AER, Draft Determination, p598.

<sup>1005</sup> AER, Draft Determination, pp562-580.

The AER also states in its Draft Determination that the NEVA authorises it to deduct the 2001-05 negative carryover as part of enforcing the ESCV's 2006-10 EDPR. That is incorrect and an error of law for the following reasons:

- The AER's powers under the NEVA in relation to the ESCV's 2006-10 EDPR only apply during the term of the ESCV's 2006-10 EDPR, ie 1 January 2006 to 31 December 2010. From 1 January 2011, the AER's powers in relation to the economic regulation of DNSPs are as set out in the NEL and the Rules. The NEVA does not confer on the AER a power to effectively carry over parts of the ESCV's 2006-10 EDPR into 2011-15 and to disregard the limitations on its powers under the NEL and the Rules, which is the effect of what the AER proposes in the Draft Determination.
- The AER states that section 25 of the NEVA authorises it to enforce the ESCV's 2006-10 EDPR and that carrying over the 2001-05 negative carryover is part of the exercise of that enforcement power. That is incorrect and an error of law because:
  - section 25 only applies *'if a relevant distributor has contravened or is contravening or, in the opinion of the AER, is likely to contravene'* the ESCV's 2006-10 EDPR or certain conditions of its distribution licence;
  - Powercor Australia has not contravened the ESCV's 2006-10 EDPR or its distribution licence, so section 25 does not apply and is simply not relevant to this issue;
  - in any event, the only enforcement action authorised under section 25 is to serve a provisional order or final order requiring compliance with the ESCV's 2006-10 EDPR, and the NEVA does not authorise the AER to include a matter in its Final Determination as part of its enforcement powers.
- The ESCV's 2006-10 EDPR does not set out a clear position on the treatment of the 2001-05 negative carryover after 2010 and does not require that it must be deducted in 2011-15. The ESCV's 2006-10 EDPR only states the ESCV's expectation that the 2001-05 negative carryover could 'possibly' be deducted from any future positive carryover amount.

The AER has no power to take the 2001-05 negative carryover into account in making its 2011-15 determination for the following reasons:

- The AER's only power under the NEL or Rules in relation to the carrying over of efficiency gains or losses from periods prior to the commencement of the 2011-15 regulatory control period is to apply a building block revenue increment or decrement under clause 6.4.3(a)(6) of the Rules.
- Clause 6.4.3(a)(6) only empowers the AER to apply revenue increments or decrements *'arising from the application of a control mechanism in the previous regulatory control period'*.
- The carrying over of the 2001-05 negative carryover is not a revenue increment or decrement *'arising from the application of a control mechanism in the previous regulatory control period'*.



Powercor Australia also notes that the AER's reasoning in relation to the 2001-05 negative carryover is inconsistent with its reasoning and conclusions in other parts of the Draft Determination. In section 9.5.4 of the Draft Determination, the AER rejected Jemena's proposal that it be compensated for financing costs associated with the overspend of its capital expenditure allowance for 2006-10.<sup>1006</sup> The AER accepted in the Draft Determination that the ESCV stated in the ESCV's 2006-10 EDPR that DNSPs overspending their capex allowances should be able to recover financing costs by rolling them into the 2011 opening RAB in the Final Determination. However, the AER determined that it was unable to give effect to that expectation because the relevant provisions of the Rules do not allow it to make such adjustments to the opening RAB.

The AER's approach in section 9.5.4 of the Draft Determination is correct, but it is inconsistent with its approach to the 2001-05 negative carryover. In section 9.5.4, the AER accepted that the ESCV's 2006-10 EDPR provided for financing costs to be included in the opening RAB for 2011 and that the ESCV had an expectation that the AER would do so, but the AER acknowledged that it was unable to give effect to that provision of the ESCV's 2006-10 EDPR and the ESCV's expectation unless there was an express provision in the Rules allowing to it make such an adjustment the RAB. In contrast, the AER's reasoning in relation to the 2001-05 negative carryover is that it must give effect to the ECM provisions in the ESCV's 2006-10 EDPR and the ESCV's expectation that the 2001-05 negative carryover could (possibly) be deducted from 2006-10 positive carryovers, regardless of whether there is any Rules provision allowing it to do so. That is incorrect. As the AER notes in section 9.5.4, the AER can only give effect to the provisions and expectations in the ESCV's 2006-10 EDPR if it is permitted to do so by the relevant provisions of the Rules.

It is also notable that in section 9.5.4 of the Draft Determination, the AER rejects Jemena's argument that this adjustment could be made under clause 6.4.3(a)(6) and the AER acknowledges that it only has a power under that section if the matter arises from the application of a control mechanism in the ESCV's 2006-10 EDPR. In relation to the 2001-05 negative carryover, the AER makes no similar attempt to analyse the extent of its powers under clause 6.4.3(a)(6) and does not explain the basis on which carrying over the 2001-05 negative carryover is a matter that arises from the application of a control mechanism in the ESCV's 2006-10 EDPR. The ESCV's statements about how the 2001-05 negative carryover may possibly be treated in the future do not form part of the 'control mechanism' in the ESCV's 2006-10 EDPR.

In addition, it is not appropriate for the AER to take the 2001-05 negative carryover into account in making its Final Determination. To do so would be inconsistent with the NEO, the revenue and pricing principles and the objectives of the EBSS. This view was confirmed in the expert report from NERA that was provided with Powercor Australia's Initial Regulatory Proposal.<sup>1007</sup>

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<sup>1006</sup> AER, Draft Determination, p449.

<sup>1007</sup> NERA, Treatment of Accrued Carryovers in the 2011-15 Regulatory Period, 22 December 2009, provided by Powercor Australia 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).

The AER states that it is not appropriate to apply the requirements of the NEL and Rules retrospectively to the ESCV's ECM.<sup>1008</sup> As explained in section 14.4.3.4 below, that comment shows a misunderstanding of the concept of retrospectivity.

Powercor Australia's proposed adjustments, and the reasoning to support those adjustments, does not involve retrospective application of the Rules. The decision that the AER is required to make is a decision under clause 6.4.3(a)(6) in relation to the amount of the revenue increments or decrements that arise from the carryover of gains or losses into the 2011-15 regulatory control period. That decision relates to Powercor Australia's revenue requirements for the forthcoming regulatory control period. It is a decision about Powercor Australia'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.

## **14.4 Exclusion of uncontrollable costs and removal of efficiency adjustments**

### **14.4.1 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia proposed that adjustments to the ESCV's operating expenditure benchmarks or Powercor Australia's actual opex figures were required for the purposes of the 2006-10 efficiency carryover calculation in relation to:

- increased vegetation management costs;
- ATO investigation and enforcement costs in 2008-09;
- superannuation costs in 2006-09;
- GSL payments in 2006-09;
- removal of the ESCV's \$5.5 million (\$2004) efficiency adjustment; and
- removal of the ESCV's 0.39 per cent partial productivity factor adjustment.<sup>1009</sup>

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.<sup>1010</sup>

Powercor Australia also provided an expert report from NERA, which stated that in order to be consistent with the NEO, the revenue and pricing principles and

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<sup>1008</sup> AER, Draft Determination, p576.

<sup>1009</sup> Initial Regulatory Proposal, pp254-262.

<sup>1010</sup> Initial Regulatory Proposal, pp254-262.

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.<sup>1011</sup>

#### **14.4.2 AER's Draft Determination**

In the Draft Determination, the AER rejected all of Powercor Australia's proposed adjustments.

While the AER's explicit consideration of Powercor Australia'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 Powercor Australia's proposed adjustments to properly understand the AER's reasons for rejecting Powercor Australia'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).<sup>1012</sup>

The AER also made the following additional observations in section 13.5.5 in considering Powercor Australia'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.<sup>1013</sup>
- 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

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<sup>1011</sup> NERA, Treatment of Accrued Carryovers in the 2011-15 Regulatory Period, 22 December 2009, provided by Powercor Australia 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).

<sup>1012</sup> AER, Draft Determination, p594.

<sup>1013</sup> AER, Draft Determination, p592.

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.<sup>1014</sup>

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 Powercor Australia's proposed adjustments. The AER reasoning set out in section 13.5.2 of the Draft Determination that would appear to have applicability to Powercor Australia's proposed adjustments includes the following:

- 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.<sup>1015</sup>
- 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.<sup>1016</sup> 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;<sup>1017</sup> 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.<sup>1018</sup>
- It is not appropriate to apply the requirements of the NEL and Rules retrospectively to the ESCV's ECM.<sup>1019</sup>
- 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

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<sup>1014</sup> AER, Draft Determination, pp592-3.

<sup>1015</sup> AER, Draft Determination, pp570-2.

<sup>1016</sup> AER, Draft Determination, p575.

<sup>1017</sup> AER, Draft Determination, p575.

<sup>1018</sup> AER, Draft Determination, p577.

<sup>1019</sup> AER, Draft Determination, p576.

2006-10 was consistent with the Rules, the NEO and the revenue and pricing principles.<sup>1020</sup>

Accordingly, while the AER's stated reasons for rejecting all of Powercor Australia's proposed adjustments were limited to the 3 reasons set out at the beginning of this section, Powercor Australia 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 Powercor Australia.
- 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.
- 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 Powercor Australia's past behaviour;
  - Powercor Australia 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 Powercor Australia; 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

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<sup>1020</sup> AER, Draft Determination, pp576 & 578.



and pricing principles because the requirements of the Tariff Order under which the ESCV's ECM was made are similar to the Rules requirements.

#### **14.4.3 Powercor Australia's response to the AER's Draft Determination**

The AER's decision in the Draft Determination to reject Powercor Australia'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.

Powercor Australia 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 Powercor Australia's proposed adjustments.

##### **14.4.3.1 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.<sup>1021</sup>

The ECM in the ESCV's 2006-10 EDPR did not explicitly allow for adjustments in relation to the specific costs that Powercor Australia 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, Powercor Australia'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

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<sup>1021</sup> AER, Draft Determination, p594.



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.<sup>1022</sup>

- 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,<sup>1023</sup> adjustments to carryover amounts for the preceding period were determined by the ORG at the end of that regulatory period.<sup>1024</sup> 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 regulatory period. For example, the ESCV in the ESCV's 2006-10 EDPR made adjustments to Powercor Australia'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.<sup>1025</sup> 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.

#### **14.4.3.2 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.

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<sup>1022</sup> See for example, ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), pp419-421.

<sup>1023</sup> ORG Appeal Panel Decision (Attachment 214 to this Revised Regulatory Proposal).

<sup>1024</sup> See for example ORG, ORG's 2001-05 EDPR, Volume 1, Chapter 5 (Attachment 213 to this Revised Regulatory Proposal), p100.

<sup>1025</sup> ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), pp419-420.

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 section 14.2.4 above, 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 Powercor Australia'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.

**14.4.3.3 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;
- Powercor Australia 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.

Powercor Australia 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, Powercor Australia rejects the AER's conclusion that Powercor Australia did not have any expectation in 2006-10 that its proposed adjustments would be made. To the contrary, throughout the 2006-10 period, Powercor Australia 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 Powercor Australia's proposed adjustments involve an application of the ESCV ECM's 'like for like' principle, it follows that the making of Powercor Australia's proposed adjustments is consistent with Powercor Australia'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 Powercor Australia'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.

Powercor Australia'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 Powercor Australia 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 Powercor Australia'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:<sup>1026</sup>

*'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:<sup>1027</sup>

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<sup>1026</sup> ORG Appeal Panel Decision (Attachment 214 to this Revised Regulatory Proposal), pp5-9.

<sup>1027</sup> ESCV, EDPR 2006-10, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), pp159 and 419.

*'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.*

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 Powercor Australia, 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 Powercor Australia 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 Powercor Australia 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'*.<sup>1028</sup> 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 Powercor Australia 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. Powercor Australia's proposed adjustments are simply an application of this principle that was accepted by the ESCV in the ESCV's 2006-10 EDPR.

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)'*.<sup>1029</sup>

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. Powercor Australia does not consider that adjustments for windfall gains would be required if Powercor Australia's proposed adjustments are made.

#### **14.4.3.4 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.<sup>1030</sup>

This comment by the AER misunderstands the concept of retrospectivity.

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<sup>1028</sup> AER, Draft Determination, p594.

<sup>1029</sup> AER, Draft Determination, p594.

<sup>1030</sup> AER, Draft Determination, p576.



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.<sup>1031</sup>

This distinction was explained by the Supreme Court of Victoria as follows:<sup>1032</sup>

*'[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.'*

As explained in section 14.2.4 above, Powercor Australia's proposed adjustments, and the reasoning to support those adjustments, does not involve retrospective application of the Rules. The AER is required to make a determination regarding revenue increments or decrements for 2011-15, which is a decision about Powercor Australia's future rights and is not a retrospective decision. In making that decision, the AER is required by the NEL to have regard to the NEO and revenue and pricing principles.

**14.4.3.5 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.<sup>1033</sup> 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 Powercor Australia'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 Powercor Australia'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,<sup>1034</sup> and that is also the case under the Rules. Accordingly, any similarity between the Tariff Order and the Rules supports Powercor Australia's adjustments and is not a reason for rejecting them.

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<sup>1031</sup> D.C. Pearce, *Statutory Interpretation in Australia*, 6<sup>th</sup> edition, 2006, Chapter 10 (Attachment 219 to this Revised Regulatory Proposal), p309.

<sup>1032</sup> *Robertson v City of Nunawading* [1973] VR 819, at 824.

<sup>1033</sup> AER, *Draft Determination*, p576.

<sup>1034</sup> ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), p415-438.



#### **14.4.3.6 Inconsistency between the AER's rejection of these adjustments and the AER's decision to make its own adjustments**

Powercor Australia'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.

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:<sup>1035</sup>

*'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:<sup>1036</sup>

*'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.'*

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<sup>1035</sup> AER, Draft Determination, p583 (footnotes omitted).

<sup>1036</sup> AER, Draft Determination, p583.

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:<sup>1037</sup>

*'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.*

...

*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:<sup>1038</sup>

*'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 Powercor Australia'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 Powercor Australia's proposed adjustments. It is unreasonable and incorrect for the AER to fail to apply that principle to Powercor Australia's proposed adjustments and to reject those adjustments because they were not explicitly provided for by the ESCV. That is particularly so when the

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<sup>1037</sup> AER, Draft Determination, p587, p588 (footnotes omitted).

<sup>1038</sup> AER, Draft Determination, p561.

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.

#### **14.4.3.7 Vegetation management costs**

The reasons justifying Powercor Australia's proposed adjustments can be demonstrated by applying them to the adjustment for increased vegetation management costs, which is the largest proposed adjustment. The explanation below is based on the latest available facts and cost information, and updates the information provided in the Initial Regulatory Proposal.

Powercor Australia proposes adjustments to actual opex of \$1,496,000 in 2008 and \$4,498,000 in 2009 for the purposes of calculating the 2006-10 carryover amounts. This adjustment relates to increased vegetation management costs incurred by Powercor Australia in LBRAs to comply with the 2005 Line Clearance Regulations and prepare for the expiry on 30 June 2010 of Powercor Australia's current partial exemptions from the 2005 Line Clearance Regulations.<sup>1039</sup>

Powercor Australia incurred this additional expenditure in 2008 and 2009 in compliance with its regulatory obligations, but this expenditure was not provided for in the ESCV's opex benchmarks in the ESCV's 2006-10 EDPR. As a result, it is necessary to remove this additional expenditure from Powercor Australia's opex figures for 2008 and 2009 in order to allow a 'like for like' comparison between Powercor Australia's actual expenditure and the ESCV's benchmarks when determining the 2006-10 carryover amounts.

This adjustment is consistent with:

- the ORG Appeal Panel Decision, which required adjustments to be made to address any changes in the scale or scope of a DNSP's operations that were not reflected in the original benchmarks;
- the ESCV's 'like for like' principle that actual expenditure must be adjusted so that it can be compared with the original benchmarks on a 'like for like' basis;
- Powercor Australia's resultant legitimate expectation, at the time of incurring the additional vegetation management expenditure in 2008 and 2009, that any adjustments required by the 'like for like' principle, including in particular an adjustment in respect of this additional vegetation management expenditure, would be made at the end of the 2006-10 regulatory period;
- the AER's acceptance and application of the 'like for like' principle in section 13.5.4 of the Draft Determination;
- the NEO and revenue and pricing principles, including providing DNSPs with effective incentives in order to promote economic efficiency and the efficient provision of electricity network services; and

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<sup>1039</sup> On 21 December 2005, ESV granted Powercor Australia a partial exemption from its obligations under the 2005 Line Clearance Regulations (Attachment 249 to this Revised Regulatory Proposal). In relation to LBRAs, the exemption provided that Powercor Australia is exempted from the requirement to maintain a clearance space under clause 2.1 of the 2005 Line Clearance Code provided that Powercor Australia has a management plan that outlines an inspection/clearing/pruning cycle that is designed to achieve, under normal growth conditions, the minimum clearance space on a two yearly cycle for high voltage lines and no more than a three yearly cycle for low voltage lines. This exemption expired on the expiry of the 2005 Line Clearance Regulations on 30 June 2010. ESV has confirmed that it will not issue Powercor Australia with a replacement exemption.

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- the EBSS principles set out in clause 6.5.8 of the Rules, including providing for a fair sharing of efficiency gains/losses and providing DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex.

These principles and Powercor Australia's legitimate expectations require that any actual expenditure that was incurred by Powercor Australia in 2006-10 as a result of unforeseen and uncontrollable changes in the scale and scope of the activities that Powercor Australia was required to undertake in that period must be removed from the actual expenditure figures for 2006-10 when calculating the 2006-10 carryover amount.

Actual expenditure of \$1,496,000 and \$4,498,000 was incurred by Powercor Australia in 2008 and 2009 respectively on compliance with the 2005 Line Clearance Regulations and in preparation for the expiry of Powercor Australia's exemptions on 30 June 2010.

This expenditure relates to an uncontrollable change in the scale and scope of Powercor Australia's activities compared with the activities reflected in the operating expenditure forecasts that were set by the ESCV and ESCV Appeal Panel for 2006-10. The fact that this expenditure was not included in 2006-10 opex benchmarks is demonstrated by the following:

- The ESCV's 2006-10 EDPR clearly stated that the only activities for compliance with the 2005 Line Clearance Regulations in LBRAs that were included in the opex forecasts were those activities that are required to achieve 'practical compliance' with the 2005 Line Clearance Regulations. For example, the ESCV's 2006-10 EDPR stated:<sup>1040</sup>

*'Given that ESV has indicated that it only intends to enforce literal compliance with the requirements imposed by the Regulations as to the clearance between electric lines and vegetation during Proclaimed Fire Declaration Periods, the Commission considers that a reasonable allowance for the costs of complying with these Regulations is one that is based on literal compliance with the Regulations during Proclaimed Fire Declaration Periods (as opposed to during periods outside Proclaimed Fire Declaration Periods).'*

- The ESCV Appeal Panel Decision on Powercor Australia's 2006 appeal in relation to vegetation management affirmed the ESCV's approach and confirmed that the opex benchmarks only include expenditure to achieve 'practical compliance' with the 2005 Line Clearance Regulations.<sup>1041</sup> The ESCV Appeal Panel process and decision is explained in the chronology set out in Appendix 6.1 of this Revised Regulatory Proposal in relation to the proposed step change for compliance with the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations.
- The activities engaged in by Powercor Australia during 2008 and 2009 in LBRAs to comply with the 2005 Line Clearance Regulations and prepare for the expiry of the exemptions were in addition to those activities required to achieve 'practical compliance' with the 2005 Line Clearance Regulations.

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<sup>1040</sup> ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), p224.

<sup>1041</sup> ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal).

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- The following table shows the difference between Powercor Australia's compliance policy in 2005 and the compliance policy which it has sought to implement since 2006:

Pre 2006	Post 2006
<p>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.</p> <p>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.</p> <p>Those compliance targets were:</p> <ul style="list-style-type: none"> <li>• Spans assigned code 55: <ul style="list-style-type: none"> <li>○ surrounding 66kV powerlines lines actioned within 24 hours;</li> <li>○ surrounding 22kV powerlines actioned within 28 days;</li> <li>○ surrounding low voltage powerlines actioned within 6 months.</li> </ul> </li> <li>• Spans assigned code 56: <ul style="list-style-type: none"> <li>○ surrounding 66kV powerlines lines actioned within 4 months;</li> <li>○ surrounding 22kV and low voltage powerlines actioned within 12 months.</li> </ul> </li> </ul>	<p>Inspection is undertaken for vegetation surrounding high voltage powerlines every 2 years and for vegetation surrounding low voltage powerlines every 3 years.</p> <p>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.</p>

Table 14.1: Changes to compliance with clearance spaces in LBRA

This change in the scale and scope of Powercor Australia's activities and the resulting expenditure incurred in 2008 and 2009 was unforeseen by the ESCV/ESCV Appeal Panel when setting the opex benchmarks for 2006-10. Indeed, the additional activities by Powercor Australia that were required for compliance with the 2005 Line Clearance Regulations and in preparation for the expiry of the exemptions were expressly excluded from the ESCV's 2006-10 EDPR's opex forecasts. This fact is demonstrated by the following:

- The ESCV's 2006-10 EDPR shows that the ESCV did not include any expenditure associated with these activities in its expenditure forecasts for 2006-10. In so doing, the ESCV did not make a finding on whether the activities were required to ensure compliance with Powercor Australia's obligations under the 2005 Line Clearance Regulations. Instead, the ESCV found that the forecasts should not include any additional expenditure for activities to achieve compliance because ESV was unlikely to enforce Powercor's obligations.<sup>1042</sup>
- The ESCV Appeal Panel Decision shows that the ESCV Appeal Panel also did not allow any expenditure associated with these activities. As with the ESCV, the ESCV Appeal Panel did not make a finding on whether the activities were

<sup>1042</sup> ESCV, 2006-10 EDPR, Volume 1 (Attachment 31 to this Revised Regulatory Proposal), p224.



required to ensure compliance with Powercor's obligations, and instead its decision was based on a view that ESV was unlikely to enforce Powercor Australia's obligations.<sup>1043</sup>

That change in scale and scope and the resulting additional expenditure was uncontrollable. If Powercor Australia did not undertake these additional activities and incur this additional expenditure, and instead only undertook the scope and scale of activities that were allowed for in the ESCV's opex forecasts (i.e. 'practical compliance'), Powercor Australia would be in breach of the 2005 Line Clearance Regulations and it would also be in breach of the 2010 Line Clearance Regulations. The consequences of failing to undertake these additional activities is explained in Appendix 6.1 of this Revised Regulatory Proposal in relation to the proposed step change for compliance with the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations.

The ESCV and ESCV Appeal Panel stated that additional activities and expenditure were not required because ESV had stated that it would not enforce those obligations. Powercor Australia does not accept that proposition, because Powercor Australia will still be in breach of the 2005 Line Clearance Regulations and subject to potential criminal and civil action regardless of ESV's stated enforcement intentions.

Even if the AER applies a similar approach to the ESCV and ESCV Appeal Panel in relation to the effects of ESV's enforcement intentions, the change in the scale and scope of Powercor Australia's activities was nonetheless uncontrollable. ESV's conduct since the date of the ESCV's EDPR 2006-10 and ESCV Appeal Panel Decision shows that, contrary to the findings of the ESCV and ESCV Appeal Panel, ESV's practice in 2006-10 has been to enforce compliance with the 2005 Line Clearance Regulations at a higher level than 'practical compliance' and to require Powercor Australia to undertake additional activities and incur additional expenditure from 2008 onwards to prepare for full compliance following expiry of Powercor Australia's exemptions.

This change in ESV's enforcement approach is demonstrated by correspondence from ESV in respect of Powercor Australia's Vegetation Management Plans, where ESV refused to approve Powercor Australia's plans and required that Powercor Australia commence a process during the 2006-10 period to achieve a higher level of compliance and to achieve full compliance following the expiry of Powercor Australia's exemptions. The change in ESV's approach is explained in more detail in Appendix 6.1 of this Revised Regulatory Proposal and demonstrated by the chronology set out at the end of that Appendix. Powercor Australia could not meet ESV's requirements without incurring this additional expenditure in 2008 and 2009.

It therefore follows that Powercor Australia has incurred additional expenditure in 2008 and 2009 in relation to vegetation management that was caused by an uncontrollable change in the scale and scope of its activities and that was not included in the ESCV's 2006-10 expenditure benchmarks. Accordingly, the AER is required to adjust Powercor Australia's opex figures to exclude this additional expenditure when calculating the 2006-10 carryover amounts.

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<sup>1043</sup> ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal), p8.



A failure to do so would be incorrect and unreasonable. It would be inconsistent with the NEO and the revenue and principle principles. It would also be inconsistent with Powercor Australia's legitimate expectations held during 2006-10, including in particular at the time of incurring additional expenditure in 2008 and 2009 in relation to vegetation management, and irreconcilable with the AER's approach to its own adjustments to the carryover amounts in section 13.5.4 of the Draft Determination where the AER clearly accepts and applies the 'like for like' principle, including to adjustments that were not provided for or contemplated by the ESCV. No reasonable regulator would accept the 'like for like' principle and apply it to its own proposed adjustments but then fail to apply it to Powercor Australia's vegetation management and other adjustments.

## **14.5 The AER's adjustments to the 2006-10 carryover amounts**

### **14.5.1 AER's Draft Determination**

In the Draft Determination, the AER made adjustments to Powercor Australia's proposed 2006-10 carryover amounts in relation to the following matters:

- network growth;
- provisions;
- licence fees;
- related party margins;
- AMI reclassification; and
- non-recurrent expenditure.<sup>1044</sup>

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.<sup>1045</sup>

These adjustments were not set out in Powercor Australia's Initial Regulatory Proposal.

### **14.5.2 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia accepts the AER's adjustments in the Draft Determination in relation to the following matters:

- AMI reclassification; and
- related party margins.

Powercor Australia accepts the AER's proposal that an adjustment should be made in relation to network growth. However, Powercor Australia does not accept the AER's estimated 2010 volume inputs for this adjustment. As explained in Chapter 7 of this Revised Regulatory Proposal, Powercor Australia does not accept the AER's approach to scale escalation, and Powercor Australia proposes that this adjustment should be calculated in accordance with Powercor Australia's approach to scale escalation set out in Chapter 7.

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<sup>1044</sup> AER, Draft Determination, pp596-597.

<sup>1045</sup> AER, Draft Determination, p583.

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Powercor Australia accepts the AER's proposal that an adjustment should be made in relation to licence fees, but Powercor Australia does not accept the amount of the AER's proposed adjustment.

Powercor Australia 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 ATO costs, superannuation and GSL payments in the 2006-08 period. Powercor Australia's proposed adjustments set out in section 14.4 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 14.4 of this Revised Regulatory Proposal are accepted.

Powercor Australia 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 Powercor Australia 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, Employee Entitlements, Stock Writedown and Vegetation Management 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, Powercor Australia 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 Powercor Australia'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.

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	2006	2007	2008	2009
	Labour Costs	Labour Costs	Labour Costs	Labour Costs
Operating Expenditure				
Maintenance Expenditure				
Capital Expenditure				
Total				

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 Powercor Australia's letter to the AER of 3 February 2010 regarding 'Regulatory Accounts, Provisions and AMI Adjustment to Regulatory Accounts'.<sup>1046</sup>
- Stock Writedown (2008): The provision statement contained in the 2008 Regulatory Accounts is incorrect. In 2008, the Powercor Australia provision statement includes a write-down of obsolete telecommunications stock. The value was incorrectly included as Regulated by Price Cap. However, it should have been included as an Adjustment because it relates to non-regulated activity. The AER adjusted Powercor Australia's operating costs. However, the Profit and Loss Statement in the Regulatory Accounts has been adjusted by allocating the offsetting cost to non-regulated activity.
- Vegetation Management (2006-07): In 2006 and 2007 the non-current portion of the Powercor Australia provision for vegetation management was restated to reflect its present value in accordance with accounting standards. The amount of the re-statement was shown as an 'Other Adjustment' with an explanatory note under the provision statement in the Regulatory Accounts. The AER excluded the 'Other Adjustments' item, however, in this case the offsetting expense was included in the Profit and Loss Statement so operating costs should be adjusted.

Powercor Australia recognises the AER will require a statement from its external auditor, Deloitte, particularly in relation to amendments to historical provision statements. Accordingly, Powercor Australia engaged Deloitte to review all the proposed movements in provisions proposed by Powercor Australia. Deloitte has confirmed the adjustments proposed by Powercor Australia to be correct.<sup>1047</sup>

<sup>1046</sup> 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).

<sup>1047</sup> Letter from T Imbesi, Partner, Deloitte, to J Williams, Chief Financial Officer, CHEDA, titled 'Powercor Regulatory Accounts: Accounting treatment of provisions', 20 July 2010 (Attachment 218 to this Revised Regulatory Proposal).

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## 14.6 Powercor Australia's Revised Regulatory Proposal

Powercor Australia does not make any amendments to its Initial Regulatory Proposal in relation to the 2001-05 negative carryover. Powercor Australia maintains that the AER cannot and should not deduct the 2001-05 negative carryover from Powercor's positive 2006-10 carryover amount.

Powercor Australia 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, Powercor Australia does not accept the AER's position in the Draft Determination.

Powercor Australia amends its Initial Regulatory Proposal to incorporate adjustments to the opex benchmarks and outturn opex as set out in Table 14.3 below.

Powercor Australia updates the amount of its proposed adjustment for increased vegetation management costs based on the most recent available information. The updated adjustment is -\$1,496,000 in 2008 and -\$4,498,000 in 2009.

Powercor Australia'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	135,279	138,386	141,050	144,112	147,834					
Opex benchmarks after adjustments	138,163	141,771	146,578	156,159	160,475					
Outturn opex (refer Chapter 6)	134,771	117,817	116,441	137,256						
Outturn opex after adjustments	134,771	117,817	114,041	130,267						
Incremental saving	3,392	20,562	8,583	(6,645)	-					
	Carryover gains									
2006		3,392	3,392	3,392	3,392	3,392				
2007			20,562	20,562	20,562	20,562	20,562			
2008				8,583	8,583	8,583	8,583	8,583		
2009					(6,645)	(6,645)	(6,645)	(6,645)	(6,645)	
2010						0	0	0	0	0
Carryover amount						25,892	22,500	1,938	(6,645)	0

**Table 14.3 2006-10 efficiency carryover amounts**

## **15. EFFICIENCY BENEFIT SHARING SCHEME**

In this Chapter of the Revised Regulatory Proposal, Powercor Australia responds to Chapter 14 of the Draft Determination regarding the EBSS.

### **15.1 Summary of key points**

Powercor Australia does not accept the AER's decision to reject Powercor Australia's proposal that any events that are proposed by Powercor Australia 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.<sup>1048</sup> 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.<sup>1049</sup>

### **15.3 Powercor Australia's Initial Regulatory Proposal**

In the Initial Regulatory Proposal, Powercor Australia 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 recommendations arising from the Bushfires Royal Commission;

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<sup>1048</sup> AER, EBSS Guideline (Attachment 215 to this Revised Regulatory Proposal).

<sup>1049</sup> AER, EBSS Guideline (Attachment 215 to this Revised Regulatory Proposal), pp6-7.



- costs arising from changes in safety regulations introduced by the ESCV;
- costs arising from changes in exposure limits introduced in the final version of the current Draft Radiation Protection Standard for Exposure Limits to Electric and Magnetic Fields 0Hz-3kHz, by the ARPANSA;
- windfarm connection costs;
- 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;
- costs arising from a network extension for remote generation event;
- fees or charges payable to the AEMO; and
- costs arising from an emissions trading scheme event.<sup>1050</sup>

#### **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.<sup>1051</sup>

The AER rejected Powercor Australia'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 through events; or
- affect revenue and not costs and therefore would not affect the EBSS calculation.<sup>1052</sup>

#### **15.5 Powercor Australia's response to the AER's Draft Determination**

##### **15.5.1 Nominated pass through events**

The AER's rejection of Powercor Australia'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.

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<sup>1050</sup> Initial Regulatory Proposal, p252.

<sup>1051</sup> AER, Draft Determination, p607.

<sup>1052</sup> AER, Draft Determination, p609.

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.<sup>1053</sup> 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.

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)*.<sup>1054</sup> 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/immateral). 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:<sup>1055</sup>

*'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 Powercor Australia 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 Powercor Australia.

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;

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<sup>1053</sup> AER, Draft Determination, p609.

<sup>1054</sup> AER, Draft Determination, p609.

<sup>1055</sup> AER, Draft Determination, p609.

- they will not adversely impact the operation of the EBSS;
- they are specific to the business;
- Powercor Australia has provided an identifiable reason for their exclusion; and
- they do not relate to an on-going business activity.<sup>1056</sup>

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, Powercor Australia maintains that any nominated pass through events proposed by Powercor Australia 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'.<sup>1057</sup>

Powercor Australia considers that the reference to 'retirement schemes' is uncertain. Powercor Australia 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, Powercor Australia proposes that the superannuation costs exclusion should cover 'superannuation costs for defined benefit and accumulation schemes'.

## **15.6 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia 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 recommendations arising from the Bushfires Royal Commission;
  - 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;

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<sup>1056</sup> AER, EBSS Guideline (Attachment 215 to this Revised Regulatory Proposal), p6.

<sup>1057</sup> AER, Draft Determination, p607.

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- 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;
- an insurance event/legal liability above insurance cap event; and
- an insurer credit risk event.

Powercor Australia'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	10,283	10,511	10,946	11,595	12,542	55,878
DMIA	600	600	600	600	600	3,000
GSL payments	1,173	1,195	1,217	1,238	1,259	6,082
Self insurance	0	0	0	0	0	0
Debt raising costs	3,187	3,475	3,764	4,043	4,321	18,791
<b>Total</b>	<b>15,243</b>	<b>15,781</b>	<b>16,527</b>	<b>17,476</b>	<b>18,722</b>	<b>83,750</b>

**Table 15.1: Forecast opex for uncontrollable cost categories**

In response to the AER's request in the note to Table 14.2 of the Draft Determination for additional information:

- the amount of opex expended on superannuation in 2009 was \$10,078,268; and
- Powercor 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 Powercor Australia to identify and explain each proposed variation or departure from the Draft Determination in respect of the EBSS.

Powercor Australia'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, Powercor Australia responds to Chapter 15 of the Draft Determination regarding the STPIS.

### **16.1 Summary of key points**

Powercor Australia 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.

Powercor Australia 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. Powercor Australia 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.

Powercor Australia 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 Powercor Australia's Initial Regulatory Proposal**

In its Initial Regulatory Proposal, Powercor Australia proposed several modifications to the application of the STPIS that was proposed by the AER in the Framework and Approach Paper.

Powercor Australia's proposed modifications to the application of the STPIS included proposing a MED threshold of 3.1 beta instead of the default 2.5 beta.<sup>1058</sup>

In its Initial Regulatory Proposal, Powercor Australia proposed that the control mechanism should include an S factor true up mechanism.<sup>1059</sup>

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 Powercor Australia's Initial Regulatory Proposal, including:

- Powercor Australia's proposed MED threshold of 3.1 beta: the AER determined that the MED threshold for Powercor Australia (and SP AusNet) should be increased from the default of 2.5 beta to 2.8 beta;<sup>1060</sup>
- Powercor Australia's proposal to combine the short rural and long rural feeder categories;<sup>1061</sup>
- Powercor Australia'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;<sup>1062</sup>
- Powercor Australia's application of a customer growth factor to its forecast GSL payments;<sup>1063</sup>
- Powercor Australia's proposal that the Final Determination should include an S factor true up mechanism.<sup>1064</sup>

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

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<sup>1058</sup> Initial Regulatory Proposal, p268.

<sup>1059</sup> Initial Regulatory Proposal, pp 326-328.

<sup>1060</sup> AER, Draft Determination, p653.

<sup>1061</sup> AER, Draft Determination, p635.

<sup>1062</sup> AER, Draft Determination, p686.

<sup>1063</sup> AER, Draft Determination, p687.

<sup>1064</sup> AER, Draft Determination, p682.



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 Powercor Australia's response to the AER's Draft Determination**

Powercor Australia 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, Powercor Australia does not accept the AER's decision not to include an S factor true up term in the control mechanism.

Powercor Australia maintains that an S factor true up term ( $T_i$ ) should be added to the control mechanism. As explained in Chapter 4, Powercor Australia 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.

Powercor Australia also does not agree with the AER's proposed method for calculating the S factor true up correction amount. Powercor Australia's reasons are set out in Appendix 16.1. Powercor Australia 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 Powercor Australia'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.

Powercor Australia 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. Powercor Australia 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, Powercor Australia'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.

Powercor Australia notes that this change in the definition means that it is not possible to compare Powercor Australia's targets with previous ESCV targets or targets for DNSPs in other States. Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia 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:

- Powercor Australia does not accept the AER's decision not to include an S factor true-up term in the control mechanism, and Powercor Australia 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
- Powercor Australia does not accept the AER's method for calculating the S factor true up amount and will provide a separate submission on that issue.
- Powercor Australia'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
<b>S Factor true up</b>	8,100	(6,457)	(3,370)	1,524	(16,964)

Table 16.1 S Factor true up building blocks

## **16.7 Regulatory Information Notice response**

Paragraph 2.1 of the Further RIN requires Powercor Australia to identify and explain each proposed variation or departure from the Draft Determination in respect of the service target performance incentive scheme.

Powercor Australia does not propose any departure from the Draft Determination in respect of the STPIS.

As identified and explained in section 16.5 above, Powercor Australia disagrees with the AER's approach to the S factor true-up, but Powercor Australia 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, Powercor Australia 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, Powercor Australia 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.
- The AER should include recommendations arising from the Bushfires Royal Commission as a nominated pass through event.
- 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, Powercor Australia 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. Powercor Australia considers that having regard to its annual revenue profile this would result in a materiality threshold for it of \$500,000 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.<sup>1065</sup> As the AER recognised in its recent Queensland and South Australian Final Determinations,<sup>1066</sup> the pass through 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

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<sup>1065</sup> 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

<sup>1066</sup> 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.

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.

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*<sup>1067</sup>. 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 Powercor Australia's Initial Regulatory Proposal**

In Chapter 12 of its Initial Regulatory Proposal, Powercor Australia:

- nominated pass through events for the regulatory control period 2011-15;<sup>1068</sup> and
- made a submission in relation to the appropriate materiality threshold for assessing pass through events.<sup>1069</sup>

Powercor Australia proposed that the materiality threshold for each nominated pass through event should be \$5 million over the regulatory control period. Powercor Australia proposed that:

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<sup>1067</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [63]-[68].

<sup>1068</sup> Initial Regulatory Proposal p282-93.

<sup>1069</sup> Initial Regulatory Proposal p294-5.

- 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 Powercor Australia in its Initial Regulatory Proposal were:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework;
- recommendations arising from the Bushfires Royal Commission;
- changes to safety regulations introduced by the ESV;
- changes to exposure limits;
- wind farm connection costs;
- a general nominated pass through event;
- a financial failure of a retailer event;
- a declared RoLR event;
- a network extension for remote generation 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.<sup>1070</sup>

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

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<sup>1070</sup> 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.



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.<sup>1071</sup> The AER changed its understanding of the meaning of foreseeability 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.<sup>1072</sup>

The AER considered it would be more likely to treat an event as a pass through event where:<sup>1073</sup>

- 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.

The AER set out the following criteria for nominating pass through events:<sup>1074</sup>

- 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.<sup>1075</sup> 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.

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<sup>1071</sup> AER, Draft Determination, p711.

<sup>1072</sup> AER, Draft Determination, p712 and p719.

<sup>1073</sup> AER, Draft Determination, p713.

<sup>1074</sup> AER, Draft Determination, pp716-7.

<sup>1075</sup> AER, Draft Determination, p709.

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.<sup>1076</sup> 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 through events in the Rules are problematic they should raise this issue with the AEMC.

The AER rejected the following pass through events nominated by Powercor Australia 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:<sup>1077</sup>

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework;
- changes to safety regulations introduced by the ESV;
- changes to exposure limits;
- recommendations arising from the Bushfires Royal Commission;
- an emissions trading scheme event; and
- 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 following events proposed by Powercor Australia on the basis that the costs of those events are recovered elsewhere in the regulatory regime:

- wind farm connection cost event as it considered these costs are recovered through connection charges;
- network extension for remote generation event as it considered these costs are recovered through connection charges;
- financial failure of a retailer event. 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.

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<sup>1076</sup> AER, Draft Determination, p709

<sup>1077</sup> AER, Draft Determination, p710.

### **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:<sup>1078</sup>

- 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.

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 Powercor Australia's response to AER's Draft Determination**

Powercor Australia has reviewed all of the matters raised by the AER in its Draft Determination.

Powercor Australia 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 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 Powercor Australia's Initial Regulatory Proposal.

Powercor Australia 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 Powercor Australia:

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<sup>1078</sup> AER, Draft Determination, p175.

- recommendations arising from the Bushfires Royal Commission;
- 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.

Powercor Australia has revised its Initial Regulatory Proposal to:

- remove specific nominated pass through events for the wind farm connection cost event and network extension for remote generation event proposed in its Initial Regulatory Proposal;
- 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 Powercor Australia, with material being interpreted according to its ordinary meaning; and
- have no materiality threshold for the financial of a retailer pass through event.

Powercor Australia's Regulatory Proposal in respect of pass through is otherwise that set out in its Initial Regulatory Proposal. Since Powercor Australia proposed a RoLR pass through event in its Initial Regulatory Proposal and the AER accepted that proposal, Powercor Australia'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.<sup>1079</sup> Powercor Australia submits that a 'regulatory change event' should encompass any change in regulatory obligation during the regulatory control period,

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<sup>1079</sup> AER, Draft Determination, p709.

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.<sup>1080</sup>

Powercor Australia 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.<sup>1081</sup> In the AEMC's Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18<sup>1082</sup> 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.'*

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

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<sup>1080</sup> 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).

<sup>1081</sup> 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.'

<sup>1082</sup> 16 November 2006 (Attachment 109 to this Revised Regulatory Proposal), pp104-5.

the regulatory control period. The AER has no basis to confine it to a change in an existing regulatory obligation.

Powercor Australia 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 Powercor Australia 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'.<sup>1083</sup> 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, Powercor Australia 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 Powercor Australia 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<sup>1084</sup> 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.

Further, these events satisfy the AER's criteria for nominated pass through events. In particular, Powercor Australia submits that:

- each of these events are foreseeable in that they can be identified in advance;

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<sup>1083</sup> AER, Draft Determination, p710.

<sup>1084</sup> 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.



- 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, Powercor Australia 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 AER's rejection of pass through for recommendations arising from the Bushfires Royal Commission**

Significantly for all Victorian rural DNSPs, the AER also rejected Powercor Australia's proposed nominated pass through for recommendations arising from the Bushfires Royal Commission on the basis that it **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'.

As the AER is aware, the Royal Commission has not yet made its recommendations following its inquiry in the Victorian Bushfires. It is not clear what form those recommendations will take and what steps Victorian DNSPs will be required to take as a result of those recommendations. It is therefore far from definite that the recommendations arising from the Bushfires Royal Commission will fall within the category of regulatory change event or service standard event. Those recommendations are, however, likely to have a material cost impact on Victorian DNSPs.

The fact that the Royal Commission's recommendations will impact upon Victorian DNSPs and require them to undertake increased activities in reducing future bushfire risks has been recognised by the AER throughout its Draft Determination<sup>1085</sup> and by the AER's consultant, Nuttall Consulting<sup>1086</sup>, yet the AER has failed to give DNSPs any certainty that they will be able to recover the costs of activities undertaken in response to those recommendations through the pass through mechanism.

Consistent with the purpose of the pass through provisions, Victorian DNSPs should not be required to bear the burden of the costs of those events. It is clear that a pass through for recommendations arising from the Bushfires Royal Commission is consistent with the requirements of the NEL and the Rules and should be accepted by the AER. The inclusion of this event will help to ensure that Powercor Australia is provided with a reasonable opportunity to recover its efficient costs, and has effective

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<sup>1085</sup> AER Draft Determination, pVIII, p273, p292 and p913.

<sup>1086</sup> Nuttall Consulting noted that *'the results from the Victorian Royal commission into the bushfires of 2009 is likely to have a significant impact upon the management of vegetation in Victoria and the roles of DNSPs. It is considered likely that any recommendations from the Royal Commission will have cost impacts upon the Victorian DNSPs'*, Nuttall Consulting, Capital Expenditure – Victorian Electricity distribution Revenue Review, 26 May 2010 p335.

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<sup>1087</sup> 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.

It also satisfies the AER's criteria for a nominated pass through event. Specifically, Powercor Australia observes that:

- there is no certainty that the event is already provided for in the defined event definitions in the Rules;
- the event is foreseeable in that the nature of the event can clearly identified;
- 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
- the pass through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

Powercor Australia submits that no reasonable decision-maker would refuse to nominate a pass through for recommendations arising from the Bushfires Royal Commission.

#### **17.5.1.4 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 'foreseeability' since the Previous Distribution Determinations. It **now** considered that 'foreseeability' 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.<sup>1088</sup> 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.<sup>1089</sup> It noted that this aim is achieved through the removal of the general pass through event and its replacement with a natural disaster event.

Powercor Australia 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.

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<sup>1087</sup> 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.

<sup>1088</sup> AER, Statement of principles for the regulation of electricity transmission revenues, Position paper, Pass-throughs and revenue-cap re-openers, December 2005.

<sup>1089</sup> AER, Draft Determination, p719.

The Explanatory Material in respect of the Rules as they apply to distribution,<sup>1090</sup> 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 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 Powercor Australia 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.

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<sup>1090</sup> 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.

Powercor Australia submits that no reasonable decision-maker would refuse to nominate a pass through for a general pass through event.

#### **17.5.1.5 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<sup>1091</sup> provisions which reflect the 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.<sup>1092</sup> 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 Powercor Australia 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.<sup>1093</sup> Powercor Australia observes that a financial failure of a retailer event was a defined event in the ESCV's 2006-10 EDPR.<sup>1094</sup> 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.<sup>1095</sup> The AEMC's observation is equally applicable to the increased risks

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<sup>1091</sup> Attachment 226 to this Revised Regulatory Proposal.

<sup>1092</sup> 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.

<sup>1093</sup> AER, Draft Determination, p722.

<sup>1094</sup> ESCV, 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p 61.

<sup>1095</sup> 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.

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 through events. Specifically, Powercor Australia 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;
- 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 Powercor Australia 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.<sup>1096</sup>

Powercor Australia'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.

#### **17.5.1.6 Electricity Safety Management Scheme**

In its Initial Regulatory Proposal, Powercor Australia 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.<sup>1097</sup> The AER rejected Powercor Australia's proposed step change.<sup>1098</sup>

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, Powercor Australia 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,

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<sup>1096</sup> Initial Regulatory Proposal p289-90.

<sup>1097</sup> Initial Regulatory Proposal, p177-78.

<sup>1098</sup> AER, Draft Determination, Appendix L, p159.



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 Powercor Australia's costs of providing direct control services. Accordingly, Powercor Australia 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 Powercor Australia 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<sup>1099</sup> 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.

Further, this event satisfies the AER's criteria for nominated pass through events. In particular, Powercor Australia 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.

Powercor Australia 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.

Powercor Australia 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.

#### **17.5.1.7 Transmission related costs event**

In Chapter 3 of this Revised Regulatory Proposal, Powercor Australia 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, Powercor Australia 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.

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<sup>1099</sup> 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.



However, as set out in Chapter 3, Powercor Australia 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, Powercor Australia 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.

Powercor Australia 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).<sup>1100</sup> 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. Powercor Australia 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.

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'.<sup>1101</sup> Powercor Australia observes that 'material' is defined in the Shorter Oxford Dictionary<sup>1102</sup>, 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. 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*'.<sup>1103</sup> 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.<sup>1104</sup> 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*'.

Powercor Australia asserts that there is a good reason for a difference between the materiality threshold for transmission and that for distribution. Further, no reasonable

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<sup>1100</sup> AER, Draft Determination, p714.

<sup>1101</sup> AER, Draft Determination, p714.

<sup>1102</sup> (5<sup>th</sup> ed 2002)

<sup>1103</sup> AER, Draft Determination, p715.

<sup>1104</sup> AER, Draft Determination, p715.

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.

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.<sup>1105</sup> 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

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<sup>1105</sup> 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.

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'.<sup>1106</sup> 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.<sup>1107</sup>

*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'.<sup>1108</sup> 'Material' is not defined in the ESCV's 2006-10 EDPR and, accordingly, it takes its ordinary meaning. Again, Powercor Australia observes that 'material' is defined in the Shorter Oxford Dictionary<sup>1109</sup>, 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:<sup>1110</sup>

*'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.

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<sup>1106</sup> ESCV's 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p61

<sup>1107</sup> 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.

<sup>1108</sup> ESCV's 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal), p61

<sup>1109</sup> (5<sup>th</sup> ed 2002).

<sup>1110</sup> 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 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 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 Powercor Australia 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 effective incentives for efficient investment in their distribution systems.

If this materiality threshold were to apply, CitiPower would be able to recover for certain pass through events, however, Powercor Australia would not be entitled to recover for those same events. This particularly the case for pass through items that may be invariant to the size of the DNSP.

The application of the materiality threshold to Powercor Australia and CitiPower based on the revenue forecast in the AER's Draft Determination is shown in the following table:



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Year	2011	2012	2013	2014	2015
Materiality threshold Powercor	\$4.1M	\$4.3M	\$4.6M	\$4.8M	\$5.0M
Materiality threshold CitiPower	\$2.1M	\$2.2M	\$2.2M	\$2.3M	\$2.5M

**Table 17.1 Application of Materiality Threshold**

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.<sup>1111</sup> 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.

*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 Powercor Australia.<sup>1112</sup> However, in making this assessment the AER has misunderstood that Powercor Australia 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 Powercor Australia 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**

Powercor Australia has revised its view of the materiality threshold given the AER's Draft Determination. In revising its view of the materiality threshold, Powercor Australia 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, Powercor Australia 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.

<sup>1111</sup> AER, South Australian Final Determination, (Attachment 22 to this Revised Regulatory Proposal), p232.

<sup>1112</sup> AER, Draft Determination, p715.



Powercor Australia 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.

Powercor Australia 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.<sup>1113</sup> As set out above, Powercor Australia 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.

Powercor Australia considers that having regard to its annual revenue profile this would result in a materiality threshold for it of \$500,000 over the regulatory control period for each nominated pass through event.

### **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, Powercor Australia 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 Powercor Australia's further consideration of the rationale for a retailer failure event, Powercor Australia has revised its view of the materiality threshold for retailer failure events. Powercor Australia 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

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<sup>1113</sup> ESCV's 2006-10 EDPR, Volume 2 (Attachment 32 to this Revised Regulatory Proposal),p61

- 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, Powercor Australia 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. Powercor Australia 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 Powercor Australia that carries the risk of retailer failure. Powercor Australia 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 Powercor Australia, it must provide compensation to Powercor Australia 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'.<sup>1114</sup> 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

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<sup>1114</sup> 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.

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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.<sup>1115</sup>

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.<sup>1116</sup> 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. ACG 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 Powercor Australia holds almost no credit support. Further, it is likely that Powercor Australia 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, 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.<sup>1117</sup> 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.<sup>1118</sup>

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<sup>1115</sup> 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.

<sup>1116</sup> 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.

<sup>1117</sup> 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  $0.1 \times 33.33$  per cent = 0.033 per cent of annual distribution service charges revenue.

<sup>1118</sup> Letter from R Hermann to ESC dated 18 August 2006 in respect of ESC Credit decision (Attachment 225 to this Revised Regulatory Proposal).

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.

#### **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, Powercor Australia 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 Powercor Australia 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 Powercor Australia.

The ESCV's 2006-10 EDPR contains a  $K_i$  term to true up the difference between estimated and actual revenues and charges for embedded generation fees and inter-DNSP charges. Powercor Australia's proposed  $KAY_i$  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.<sup>1119</sup> Powercor Australia 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 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia has revised its Regulatory Proposal to:

- remove specific nominated pass through events for the wind farm connection cost event and network extension for remote generation event proposed in its Initial Regulatory Proposal;
- 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;
  - a natural disaster event;
  - an insurance event/legal liability above insurance cap event; and
  - an insurer credit risk event;

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<sup>1119</sup> AER's Queensland Final Determination (Attachment 24 to this Revised Regulatory Proposal), p310.

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- 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 Powercor Australia's annual revenue profile this would result in a materiality threshold for it of \$500,000 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.

Powercor Australia's current Regulatory Proposal in respect of pass through is otherwise that set out in its Initial Regulatory Proposal. Since Powercor Australia proposed a RoLR pass through event in its Initial Regulatory Proposal and the AER accepted that proposal, Powercor Australia's Current Regulatory Proposal includes that event.



## **18. BUILDING BLOCK REVENUE REQUIREMENTS**

In this Chapter of the Revised Regulatory Proposal, Powercor Australia responds to Chapter 18 of the Draft Determination regarding Powercor Australia's building block revenue requirements.

### **18.1 Summary of key points**

This Chapter sets out Powercor Australia's proposed ARR 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;

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- 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 Powercor Australia's Initial Regulatory Proposal

In the Initial Regulatory Proposal, Powercor Australia proposed the ARR's set out in Table 18.1 below.<sup>1120</sup>

Building block	\$m (nominal)				
	2011	2012	2013	2014	2015
Indexation of the RAB	(54.2)	(60.5)	(66.9)	(73.6)	(80.8)
Return on capital	240.6	268.8	296.9	326.7	358.9
Depreciation	118.5	133.2	148.1	163.9	182.3
Opex	169.0	179.8	192.2	206.3	225.6
Corporate income tax	10.6	12.2	14.1	16.1	18.8
Efficiency carryover mechanism	29.0	25.8	6.3	(6.6)	-
Service incentive mechanism	16.2	(7.7)	(4.6)	0.5	(28.0)
<b>Total</b>	<b>529.7</b>	<b>551.5</b>	<b>586.0</b>	<b>633.3</b>	<b>676.8</b>

Table 18.1 Initial Regulatory Proposal - Annual revenue requirements

Powercor Australia's proposed X factors for standard control services as set out in the Initial Regulatory Proposal are summarised in Table 18.2 below.<sup>1121</sup>

	2011	2012	2013	2014	2015
X factors (per cent)	(22.30)	(5.00)	(5.00)	(5.00)	(5.00)

Table 18.2 Initial Regulatory Proposal - Proposed X factors

### 18.4 AER's Draft Determination

In the Draft Determination, the AER determined that Powercor Australia's ARR's and X factors should be as set out in Table 18.3.<sup>1122</sup>

<sup>1120</sup> Initial Regulatory Proposal, p328.

<sup>1121</sup> Initial Regulatory Proposal, p329.

<sup>1122</sup> AER, Draft Determination, p768.

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**Table 18.26 AER conclusion on Powercor's revenue requirements and X factors  
(\$'m, nominal)**

	2010	2011	2012	2013	2014	2015
Return on capital		213.4	227.2	241.4	255.9	271.0
Regulatory depreciation		62.0	68.1	74.6	81.5	88.9
Operating expenditure		123.0	127.5	133.1	141.9	147.2
Efficiency carryover amounts		0.0	16.4	0.3	-6.8	0.0
S factor amounts		16.7	-8.0	-4.8	0.9	-32.6
Tax allowance		7.7	8.6	9.2	9.8	10.6
Annual revenue requirements		422.7	439.8	453.8	483.3	485.0
Expected revenues	426.7	413.1	434.8	458.3	481.3	502.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		8.14	0.00	0.00	0.00	0.00

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 Powercor Australia's response to the AER's Draft Determination

Powercor Australia 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, Powercor Australia's proposed ARRs and X factors are as set out in Tables 18.4 and 18.5.

Building block	\$m (nominal)				
	2011	2012	2013	2014	2015
Indexation of the RAB	(56.9)	(63.7)	(70.7)	(77.9)	(85.4)
Return on capital	228.0	255.0	283.3	312.1	342.2
Depreciation	119.1	134.3	150.0	166.1	185.2
Opex	180.1	190.2	197.0	210.7	224.0
Corporate income tax	3.9	4.8	6.0	7.2	9.0
Efficiency carryover mechanism	26.6	23.7	2.1	(7.4)	0.0
Service incentive mechanism	8.3	(6.8)	(3.6)	1.7	(19.3)
<b>Total revenue requirement</b>	<b>509.1</b>	<b>537.5</b>	<b>564.1</b>	<b>612.5</b>	<b>655.7</b>

**Table 18.4: Proposed ARRs**

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	2011	2012	2013	2014	2015
X factors (per cent)	-20.63%	-1.00%	-1.00%	-1.00%	-1.00%

Table 18.5 Proposed X factors

## **18.6 Powercor Australia's Revised Regulatory Proposal**

Powercor Australia 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, Powercor Australia 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**

Powercor Australia submits that the AER should determine its prices for fee based and quote based alternative control services on the basis that Powercor Australia should be permitted to recover its efficient costs of providing alternative control services. Powercor Australia 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, Powercor Australia has made revisions to the alternative control services model used by the AER for the purposes of its Draft Determination<sup>1123</sup> in order to facilitate recovery of its efficient costs of providing alternative control services. In Powercor Australia's view, the AER should accept Powercor Australia'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 Powercor Australia 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.

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<sup>1123</sup> Provided to Powercor Australia on 7 June 2010.

## **19.3 Fee Based Services**

### **19.3.1 Initial Regulatory Proposal**

In Chapter 23 of its Initial Regulatory Proposal, Powercor Australia 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.<sup>1124</sup>

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.

Powercor Australia 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 Powercor Australia to provide it with bottom up cost build ups for all alternative control services. Accordingly, in response to the AER's request Powercor Australia was required to provide a bottom up approach to determine price caps for all alternative control services and on 3 March 2010, Powercor Australia 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. Powercor Australia'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

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<sup>1124</sup> Initial Regulatory Proposal, pp375-86.



taken to perform the services. Impaq prepared a report entitled *Impaq Consulting, Review of Distributors Proposed Rates in ACS Charges*.<sup>1125</sup>

The AER rejected Powercor Australia'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 Powercor Australia on 3 March 2010. The AER provided its model to Powercor Australia 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, Powercor Australia's business hours line worker rates were high.<sup>1126</sup>

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 Powercor Australia's proposed hourly labour rates for line workers in business and after hours times were significantly higher than industry standards.<sup>1127</sup> 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 Powercor Australia'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 Powercor Australia's reconnection, disconnection and special meter read services were reasonable.<sup>1128</sup> However, the AER did not consider that the escalation of the service provider's rates over 2012-15 was sufficiently justified.<sup>1129</sup>

#### **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 Powercor Australia had significantly overstated the times needed for many labour components.<sup>1130</sup> 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 Powercor Australia'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

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<sup>1125</sup> 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).

<sup>1126</sup> AER, Draft Determination, p854.

<sup>1127</sup> AER, Draft Determination, p855.

<sup>1128</sup> AER, Draft Determination, p855.

<sup>1129</sup> AER, Draft Determination, p855 and 863.

<sup>1130</sup> AER, Draft Determination, p858.

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.<sup>1131</sup>

#### **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:<sup>1132</sup>

*'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 Powercor Australia 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 Powercor Australia to its alternative control service charges for 2011.<sup>1133</sup>

#### **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.<sup>1134</sup>

#### **19.3.2.6 Price path – fee based services**

The AER found that Powercor Australia'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.<sup>1135</sup>

Powercor Australia 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 Powercor Australia 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.

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<sup>1131</sup> AER, Draft Determination, p858.

<sup>1132</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal) p39.

<sup>1133</sup> AER, Draft Determination, p861.

<sup>1134</sup> AER, Draft Determination, p862.

<sup>1135</sup> AER, Draft Determination, p862.

The AER said that in the absence of supporting information, it did not approve Powercor Australia's proposed prices for 2012-15 in the Draft Determination. It also considered that Powercor Australia'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 Powercor Australia 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 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 Powercor Australia to provide the following information in respect of prices which Powercor Australia 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:<sup>1136</sup>

- Reserve feeder service. Powercor Australia proposed this service as a negotiated service. The AER classified this service as an alternative control fee based service. The AER required Powercor Australia to propose a fee for this service.
- Re-test of type 5 and 6 meters service. Powercor Australia proposed this service as a standard control service. The AER classified this service as an alternative control fee based service. The AER required Powercor Australia to propose a fee for this service.

#### **19.3.3 Powercor Australia's response to AER's Draft Determination**

##### **19.3.3.1 Powercor Australia's revised model**

Powercor Australia submits that the AER should determine its prices for fee based and quote based alternative control services on the basis that Powercor Australia should be permitted to recover its efficient costs of providing alternative control services. Powercor Australia 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, Powercor Australia has made revisions to the alternative control services model used by the AER for the purposes of its Draft Determination<sup>1137</sup> in order to facilitate recovery of its efficient costs of providing alternative control services. Powercor Australia provides its revised model as an attachment to this Revised Regulatory Proposal.<sup>1138</sup>

Powercor Australia'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 Powercor Australia's view that the AER's, and Impaq's, criticisms of the model which Powercor Australia provided to the AER on 3 March 2010 are incorrect in relation to following matters:

- profit margins;

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<sup>1136</sup> AER, Draft Determination, p864.

<sup>1137</sup> Provided to Powercor Australia on 7 June 2010.

<sup>1138</sup> Attachment 19 to this Revised Regulatory Proposal.

- contract rates;
- labour rates for line workers; and
- times required per activity.

The following sections describe where Powercor Australia 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.<sup>1139</sup>

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'*.<sup>1140</sup> In support, Impaq said:<sup>1141</sup>

*'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'Donnell 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.<sup>1142</sup> Powercor Australia observes that this profit margin is more closely aligned with the profit margins for Downer EDI and Leightons referred to by Impaq.

Powercor Australia 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. Powercor Australia 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, Powercor Australia 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:

- $\$84.00 - (\$84.00 \times 0.05) = \$79.80$

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.

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<sup>1139</sup> AER Draft Determination, p852.

<sup>1140</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p38.

<sup>1141</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p38, footnote 17.

<sup>1142</sup> Norfolk, Financial Results for the Year Ended 31 March 2010, presentation dated 26 May 2010, (Attachment 229 to this Revised Regulatory Proposal), p15.

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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:

- $\$84.00 \div 1.08 \times 1.03 = \$80.11$

However, Powercor Australia 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:

- $\$84.00 \div 1.08 \times 1.057 = \$82.21$

*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.<sup>1143</sup> It requested Powercor Australia 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, Powercor Australia 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.<sup>1144</sup> 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*'.<sup>1145</sup>

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.<sup>1146</sup>

Year	2011	2012	2013	2014	2015
Rate increase	20%	50%	100%	100%	100%

**Table 19.1 AMRS rate increases**

This shows that Powercor Australia's escalation of the service providers rates over 2012-15 is justified. Powercor Australia 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.<sup>1147</sup>

*Labour rates for line workers*

In determining the labour rate for line workers to apply to Powercor Australia's fee based alternative control services and quote based alternative control services, the AER relied on Impaq's Report.

<sup>1143</sup> AER, Draft Determination, p855.

<sup>1144</sup> CHED Services Contract with AMRS for the Supply of Cyclic Field and Special Meter Reading Services (Attachment 231 to this Revised Regulatory Proposal).

<sup>1145</sup> CHED Services Contract with AMRS for the Supply of Cyclic Field and Special Meter Reading Services, (Attachment 231 to this Revised Regulatory Proposal), p59.

<sup>1146</sup> Servicestream, Presentation - Working Together CitiPower/Powercor Contract Variations October 2009, (Attachment 239 to this Revised Regulatory Proposal), p8.

<sup>1147</sup> See CitiPower's revised model for alternative control services (Attachment 19 to this Revised Regulatory Proposal).



Powercor Australia 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, Powercor Australia provided fully cost absorbed labour rates (\$2010) of \$112.76 per hour (business hours) and \$123.99 (after hours) exclusive of margin. Powercor Australia's labour rate inputs were generated using contractor costs.

Impaq's view of the labour rate for line workers was determined by:<sup>1148</sup>

- 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.<sup>1149</sup> 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 Powercor Australia an opportunity to verify Impaq's conclusions.

Impaq also had regard to Hays' salary survey for 2009.<sup>1150</sup> 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 Powercor Australia. Further, Hays' salary survey specifically states that '*[s]ome niche markets however continue to see positive growth, in particular ...utilities*'<sup>1151</sup> indicating salaries in this sector are higher than the average.

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<sup>1148</sup> AER, Draft Determination, p3.

<sup>1149</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p34.

<sup>1150</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p35.

<sup>1151</sup> Extract from Hays' salary survey 2009, *Sector Commentary, Manufacturing & Ops*, (Attachment 235 to this Revised Regulatory Proposal), p118.



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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.<sup>1152</sup>

In determining the available hours component of its bottom up build, Impaq made the following incorrect assumptions:<sup>1153</sup>

- 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;<sup>1154</sup>
- it incorrectly assumed 10 public holidays in 2010. There were actually 11 public holidays in Victoria in 2010. There were 12 public holidays for Powercor Australia under its CEPU work agreement; and
- 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 Powercor Australia's proposed rates and the rates for interstate distribution businesses<sup>1155</sup>, 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 Powercor Australia 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.<sup>1156</sup> This figure is incorrect. Rather, ETSA's 'Network Tariff and Negotiated Services, June 2010' publication reveals a labour rate of \$100 for comparable services.<sup>1157</sup> Impaq used Country Energy's and Energy Australia's labour rates for their miscellaneous services effective 1 July 2009.<sup>1158</sup> These labour rates are not comparable with Powercor Australia's labour rate because Powercor Australia's

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<sup>1152</sup> Hays, *Hays Salary Guide* 2010, (Attachment 237 to this Revised Regulatory Proposal), p121.

<sup>1153</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p37.

<sup>1154</sup> Powercor Australia (CEPU) Workplace Agreement 2007 (Attachment P0037 to the Initial Regulatory Proposal).

<sup>1155</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p45 and 49.

<sup>1156</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p40.

<sup>1157</sup> ETSA, *Network Tariff & Negotiated Services*, June 2010, (Attachment 236 to this Revised Regulatory Proposal) p63.

<sup>1158</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), pp40-1.

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 Powercor Australia, 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. Powercor Australia submits that the AER should accept the labour rates (\$2010) of \$112.76 per hour (business hours) and \$123.99 (after hours) which were included in the model Powercor Australia provided to the AER on 3 March 2010. Accordingly, Powercor Australia 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 Powercor Australia's times to be outside a reasonable range, it was appropriate to apply the highest point of Impaq's recommended times for services.

Powercor Australia submits that the AER cannot reasonably rely on Impaq's time estimates or comments in respect of Powercor Australia'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 Powercor Australia's revised alternative control services model as described below. Unlike Impaq's time estimates which are completely unsubstantiated those times are supported by Powercor Australia's actual operations.

Powercor Australia responds below to Impaq's comments in respect of the following times to perform services in section 8 of its Report:<sup>1159</sup>

- 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).

#### Field Officer Visits Special Reads BH

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. Powercor Australia has reviewed its time in line with actual reported information and considers that Jemena's allocation of 0.042<sup>1160</sup> is more in line with Powercor Australia's actual time allocation than the

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<sup>1159</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), pp51-4.

<sup>1160</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51, service 1.

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unsupported estimate provided by Impaq. Accordingly, Powercor Australia has used this time in its revised alternative control services model.

Service vehicle visits BH and AH

In respect of service vehicle visits, Impaq considered in section 8 of its Report (services 7 and 8 in its table) that:<sup>1161</sup>

- 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:<sup>1162</sup> *'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.'* Powercor Australia'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<sup>1163</sup> *'CitiPower have assumed a travel time of 45 min which seems excessive as a travel time between jobs. 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'*

In the model which Powercor Australia provided to the AER on 3 March 2010 and its revised alternative control services model, Powercor Australia has used a travel time of 40 mins for service visits. This is supported by confirmed travel times in its project management orders compared to the number of jobs completed over the years. Data from the years 2005-07 was used for the model Powercor Australia provided the AER on 3 March 2010. This 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:

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 Powercor Australia's Travel Time Data 2006-07**

<sup>1161</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.

<sup>1162</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.

<sup>1163</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.

The source spreadsheets for these travel times are provided as an attachment to this Revised Regulatory Proposal.<sup>1164</sup>

In respect of scheduling team time for 'service visits BH and AH', Impaq stated that<sup>1165</sup> *'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'*.

Powercor Australia's proposed times are supported through time confirmations within its job tracking software (SAP).<sup>1166</sup>

#### Field staff times for meter testing

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<sup>1167</sup> *'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'*. Powercor Australia'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 Impaq in its Report. Accordingly, Powercor Australia 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<sup>1168</sup> *'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%.'*

Powercor Australia observes that part of the process of isolating supply is job preparation and safety assessment. The safety assessment is undertaken using Powercor Australia's Specialist Metering Check List.<sup>1169</sup> 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. Powercor Australia confirms that the time taken to perform the task of isolating supply is 10 minutes.

The times to test a meter which Powercor Australia 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;

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<sup>1164</sup> Source spreadsheets for Powercor Australia's travel times (three worksheets for 2005, 2006 and 2007) (Attachment 228 to this Revised Regulatory Proposal).

<sup>1165</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p51.

<sup>1166</sup> SAP stands for Systems Analysis and Program and is business management software used by Powercor Australia.

<sup>1167</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.

<sup>1168</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.

<sup>1169</sup> Powercor Australia's Specialist Metering Checklist (Attachment 240 to this Revised Regulatory Proposal)

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- 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.

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
<b>Total time</b>	<b>41 minutes</b>

**Table 19.3 Time taken to perform meter equipment test – single phase BH & AH**

Powercor Australia 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:<sup>1170</sup> *‘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:

<sup>1170</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.

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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
<b>Total time</b>	<b>66 minutes</b>

**Table 19.4 Time taken to perform meter equipment test – single phase each additional meter**

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
<b>Total time</b>	<b>115 minutes</b>

**Table 19.5 Time taken to perform meter equipment test –multi phase each additional meter**

Powercor Australia 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:<sup>1171</sup> *'Testing a CT connected meter is more complicated however the times proposed by CP/PC seem excessive'*.

Powercor Australia observes that a current transformer (current transformer) 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.

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.

<sup>1171</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal), p52.



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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 Powercor Australia is not excessive. Accordingly, Powercor Australia 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 Powercor Australia 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<sup>1172</sup>. However, for the reasons set out in Chapter 8 of this Revised Regulatory Proposal, Powercor Australia asserts that the appropriate labour and materials escalators are those set out in Chapter 8.

Powercor Australia 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.

<sup>1172</sup> AER, Draft Determination, p863.

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Year	2012	2013	2014	2015
X factor	(41.6)%	(29.4)%	(0.2)%	(0.1)%

Table 19.7 X factor for fee based connection services (real)

Year	2012	2013	2014	2015
X factor	(1.6)%	(1.9)%	(2.0)%	(0.8)%

Table 19.8 X factor for other fee based services (real)

### 19.3.3.3 Changes to service classification

The AER asked Powercor Australia to provide information in respect of prices for services which Powercor Australia did not classify as alternative control services in its Initial Regulatory Proposal, but which the AER classified as alternative control services.<sup>1173</sup>

Using the approach to determining alternative control charges proposed by Powercor Australia in this Revised Regulatory Proposal, Powercor Australia 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 to this Revised Regulatory Proposal.

## 19.4 Quote Based Services

### 19.4.1 Powercor Australia's Initial Regulatory Proposal

In Chapter 23 of its Initial Regulatory Proposal, Powercor Australia 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.<sup>1174</sup>

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.

Powercor Australia 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, Powercor Australia 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:

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<sup>1173</sup> AER, Draft Determination, p864.

<sup>1174</sup> Initial Regulatory Proposal, pp386-93.

- 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.

Powercor Australia 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.<sup>1175</sup>

##### **19.4.2.2 Labour rates**

The AER observed that in comparing Powercor Australia's proposed quoted services labour rates to the charge out rates for line workers, Impaq found Powercor Australia's labour rates to be above the reasonable range.<sup>1176</sup> Consistent with its approach to fee based services, the AER considered a reasonable hourly rate for Powercor Australia'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 Powercor Australia to provide labour costs for this service in its Revised Regulatory Proposal.

##### **19.4.2.3 Changes to service classification**

The AER asked Powercor Australia to provide an hourly labour rate for the audit design service being a service which Powercor Australia proposed as standard control in its Initial Regulatory Proposal, however the AER classified as a quoted alternative control service in its Draft Determination.<sup>1177</sup>

##### **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 Powercor Australia's standard control services set out in Appendix K of its Draft Determination.<sup>1178</sup>

##### **19.4.2.5 Price path – quoted services**

The AER observed that Powercor Australia proposed its 2011 labour rate be escalated by the BIS Shrapnel labour escalator, plus CPI over the forthcoming regulatory

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<sup>1175</sup> AER, Draft Determination, p891.

<sup>1176</sup> AER, Draft Determination, p891.

<sup>1177</sup> AER, Draft Determination, p864.

<sup>1178</sup> AER, Draft Determination, p892.

period.<sup>1179</sup> The AER agreed that it was appropriate to escalate the approved 2011 labour rates for 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 Powercor Australia's standard control services.

### **19.4.3 Powercor Australia's Response to AER's Draft Determination**

#### **19.4.3.1 Powercor Australia's proposed labour rates**

Powercor Australia submits that the AER should determine a labour rate for its quoted alternative control services such that Powercor Australia is permitted to recover its efficient costs of providing those services. Powercor Australia is not able to recover those costs on the basis of its existing charges or the charges proposed in the AER's Draft Determination.

Powercor Australia'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.<sup>1180</sup> Accordingly, the AER should accept the labour rates for quoted alternative control services proposed in this Revised Regulatory Proposal which will assist Powercor Australia to recover the efficient costs of providing quoted alternative control services.

Powercor Australia provides the quoted services set out in the following table.

<b>Quoted Services provided by Powercor Australia</b>
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

**Table 19.9 Quoted services provided by Powercor Australia**

In this Revised Regulatory Proposal, Powercor Australia proposes the following labour rates for its quoted services.

<sup>1179</sup> AER, Draft Determination, p892.

<sup>1180</sup> AER, Draft Determination, p902.

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Quoted Alternative Control Services	2011 \$'s per hour per person (real \$2010 ex GST)
General line worker - business hours	\$112.11
General line worker - after hours	\$123.28
Design/survey - business hours	\$120.31
Design/survey - after hours	\$135.50
Administration	\$45.34

**Table 19.10 Labour rates for quoted services provided by Powercor Australia**

As noted above, in its Draft Determination the AER asked Powercor Australia to provide an hourly labour rate for the audit design service being a service which Powercor Australia proposed as standard control in its Initial Regulatory Proposal, however the AER classified as a quoted alternative control service in its Draft Determination. Powercor Australia 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**

Powercor Australia observes that the services provided as quoted services consist wholly of labour and materials. Powercor Australia agrees with the AER's decision that customer prices for materials for quoted services should be set at the cost of the materials to Powercor Australia.<sup>1181</sup> Powercor Australia 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
<b>Quoted Services</b>	(5.0)%	(4.6)%	(4.0)%	(3.6)%

**Table 19.11 X factors for quoted services (real)**

## **19.5 Public lighting services**

### **19.5.1 Powercor Australia's Initial Regulatory Proposal**

In Chapter 23 of its Initial Regulatory Proposal, Powercor Australia 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.<sup>1182</sup>

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

<sup>1181</sup> AER, Draft Determination, p891.

<sup>1182</sup> Initial Regulatory Proposal, pp368-75.

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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'*.

Powercor Australia'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.

Powercor Australia 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 – Powercor Australia 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 – Powercor Australia used labour rates consistent with those applied to standard control services;
- real pre-tax WACC – Powercor Australia used a WACC consistent with that applied to standard control services;
- hours per day - consistent with current award conditions, Powercor Australia amended the number of hours per day from 8<sup>1</sup>/<sub>3</sub> 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.<sup>1183</sup> Operation, repair, replacement and maintenance services however are more sporadic and, therefore Powercor Australia will not be able to negotiate such a bulk supply discount. As a substitute Powercor Australia used a previous quote of \$215 (\$2010) as a cost input;
- traffic control costs – Powercor Australia determined that the traffic control costs were \$9.61 (\$2010) per light for bulk replacement activities and likely to be higher for fault activities;
- dedicated street lighting poles – cost of pole and bracket – Powercor Australia determined that the unit costs of these activities were \$3,125 (\$2010);

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<sup>1183</sup> Quotation from the MAV for T5 public lighting (Attachment 234 to this Revised Regulatory Proposal).



- patrol costs – Powercor Australia observed that costs have been amended to \$25 per hour (\$2010) to reflect the current contract prices; and
- *existing light prices* – Powercor Australia 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.

Powercor Australia 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.<sup>1184</sup>

Powercor Australia proposed a labour rate for night patrols (after hours) which had a 15 per cent loading on the labour rate for normal hours.

Powercor Australia 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 Powercor Australia 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.<sup>1185</sup> 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.<sup>1186</sup>

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
- \$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

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<sup>1184</sup> Powercor Australia's public lighting model (March 2010).

<sup>1185</sup> AER, Draft Determination, p802.

<sup>1186</sup> Impaq, Review of Distributors Proposed Rates in ACS Charges, 2 June 2010, (Attachment 227 to this Revised Regulatory Proposal) p46.

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.<sup>1187</sup> 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)*.<sup>1188</sup> 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. Since Powercor Australia and SPAustNet are both predominately rural DNSPs the AER took SP AusNet's forecast traffic management costs for each major light type and applied these costs to Powercor Australia, adjusted by a factor of 2.26 to reflect the larger forecast number of lights in Powercor Australia's area.

#### **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 Powercor Australia'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 Powercor Australia'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

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<sup>1187</sup> AER, Draft Determination, p803.

<sup>1188</sup> AER, Draft Determination, p805.

adopted by other DNSPs and Powercor Australia had not provided substantive evidence to justify the large cost variance.<sup>1189</sup>

### **19.5.3 Powercor Australia's Response to AER's Draft Determination**

Powercor Australia has reviewed all of the matters raised by the AER in its Draft Determination, including where the AER has made adjustments to Powercor Australia's Initial Regulatory Proposal.

Powercor Australia 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:

- Powercor Australia has applied the general materials escalator proposed by it in Chapter 8 of this Revised Regulatory Proposal to materials other than poles and brackets;
- Powercor Australia has included pole and brackets cost of \$1,351.30;
- Consistent with its Initial Regulatory Proposal, Powercor Australia has proposed that 18.5 per cent of T5 (2x14W) lights would fail between bulk changes during the 2011-15 regulatory control period;
- Powercor Australia has included a cost of \$25.43 for patrol vehicles;
- Powercor Australia has included a cost of \$241 for the price of luminaires; and
- Powercor Australia has included traffic management costs of \$8.56 per light.

Powercor Australia'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.

Powercor Australia 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 Powercor Australia'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 Powercor Australia had not provided substantive evidence to justify the large cost variance.<sup>1190</sup>

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<sup>1189</sup> AER, Draft Determination, p817.

<sup>1190</sup> AER, Draft Determination, p817.

Powercor Australia has further reviewed its proposed pole and bracket costs of \$3,125. Upon further review Powercor Australia observes that the figure appeared to contain labour and other costs not related to pole and bracket costs.

Powercor Australia 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.

Accordingly, in this Revised Regulatory Proposal Powercor Australia 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, Powercor Australia provides as an attachment to this Revised Regulatory Proposal quotes from vendors for costs of various poles and brackets from which Powercor Australia derived a weighted average.<sup>1191</sup>

Accordingly, Powercor Australia 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, Powercor Australia proposed that 18.5 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 18.5 per cent for Powercor Australia in Powercor Australia's 2010 proposed tariffs for distribution, transmission and unmetered supplies for the period 1 January to 31 December 2010. These rates were apparent from Powercor Australia's model provided to the AER and in the AER's updated version of the model provided to Powercor Australia by email on 26 November 2009 in respect of the tariff approval. The AER approved Powercor Australia's tariffs on 14 December 2009. Attached to this Revised Regulatory Proposal is a copy of the AER's letter approving Powercor Australia's 2010 prices for alternative control services.<sup>1192</sup>

Accordingly, Powercor Australia submits that the AER should approve its failure rate of 18.5 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).<sup>1193</sup> In its Public Lighting Decision, the AER had observed that:<sup>1194</sup> *'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'*.

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<sup>1191</sup> Attachment 230 to this Revised Regulatory Proposal.

<sup>1192</sup> Attachment 232 to this Revised Regulatory Proposal.

<sup>1193</sup> This is apparent from the input area of the Public Lighting Cost Build up Model under the sub heading 'Inputs – all lamps'.

<sup>1194</sup> AER, Public Lighting Decision, p38.

Powercor Australia submits that the rate for patrol vehicles should be \$25.43 per hour. This is the average of the rates quoted in Powercor Australia'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<sup>1195</sup> multiplied by an approximated 40 kilometre per hour travelled by the patrol vehicle, the rate is \$29.60 per hour.

The AER should accept Powercor Australia'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 Powercor Australia's proposed cost.

### **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.<sup>1196</sup> 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.

Powercor Australia 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, Powercor Australia proposed a cost of \$215 per luminaire based on an ordering quantity of 100. This cost was based on a quote obtained in 2008. Powercor Australia has recently obtained a new quote for 100 luminaires from Pierlite Australia Pty Ltd. The quote shows a cost of \$241 per luminaire.<sup>1197</sup>

Powercor Australia 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, Powercor Australia 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 Powercor Australia's 'equivalent' DNSP.

Powercor Australia has reviewed its traffic management costs and has revised its proposed traffic management costs to \$8.56 per light.

Powercor Australia 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.

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<sup>1195</sup> ATO, Tax Return Information on Work-related Car Expenses (Attachment 238 to this Revised Regulatory Proposal).

<sup>1196</sup> This is apparent from the 'Unit cost – luminaire' section of the AER's model under the 'Energy Efficient Lighting' subheading.

<sup>1197</sup> Quotation from Pierlite Australia Pty Ltd for cost of luminaires dated 24 June 2010 (Attachment 233 to this Revised Regulatory Proposal).

### 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.<sup>1198</sup> Powercor Australia 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	(2.4)%	(3.7)%	4.6%	3.1%

Table 19.12 X factors for public lighting (real)

## 19.6 Powercor Australia's Revised Regulatory Proposal

Powercor Australia 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, Powercor Australia 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.

Powercor Australia'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.

Powercor Australia 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:

- Powercor Australia has applied the general materials escalator proposed by it in Chapter 8 of this Revised Regulatory Proposal to materials other than poles and brackets;
- Powercor Australia has included pole and brackets cost of \$1,351.30;
- Consistent with its Initial Regulatory Proposal, Powercor Australia has proposed that 18.5 per cent of T5 (2x14W) lights would fail between bulk changes during the 2011-15 regulatory control period;
- Powercor Australia has included a cost of \$25.43 for patrol vehicles;
- Powercor Australia has included a cost of \$241 for the price of luminaires; and
- Powercor Australia has included traffic management costs of \$8.56 per light.

Powercor Australia's proposed charges for public lighting services are provided in Appendix 9.1 to this Revised Regulatory Proposal.

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<sup>1198</sup> AER, Framework and Approach Paper, p79.



## **Appendix 1.1 -Key Assumptions Underlying Capex and Opex Forecasts in Powercor Australia's Revised Regulatory Proposal**

This Appendix sets out the key assumptions which underlie:

- the proposed capex forecast as set out and included in Powercor Australia's building block proposal; and
- the proposed opex forecast as set out and included in Powercor Australia'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 Powercor Australia 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 Powercor Australia 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 Powercor Australia 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 Powercor Australia and reflected in 2009 average costs of works will be the

unescalated unit rates incurred by Powercor Australia 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. **Powercor Australia's internal documents:** Powercor Australia'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. **Powercor Australia'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 Powercor Australia's distribution network consistent with Powercor Australia's 'Network Augmentation Planning Policy and Guidelines'. It would also manage Powercor Australia's assets in accordance with Powercor Australia's asset management documents. This assumption relates to reinforcement and reliability and quality maintained capex.
3. **Expenditure on new customer connections:** Powercor Australia'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:** Powercor Australia'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.

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2. **Step change:** Powercor Australia's proposed step changes will occur and the effect on Powercor Australia's opex in the 2011-15 regulatory control period relative to its 2009 opex will be as forecast by Powercor Australia.
3. **Powercor Australia's policies, strategies and procedures:** Powercor Australia'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 Powercor Australia'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 Powercor Australia Ltd ACN 064 651 109 hereby certify that the key assumptions which:

1. underlie:
  - a) the proposed capital expenditure forecast as set out and included in Powercor Australia's building block proposal; and
  - b) the proposed operating and maintenance expenditure forecast as set out and included in Powercor Australia's building block proposal; and
2. are also set out and included in Powercor Australia's building block proposal, are reasonable.

Signed:



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dated this 16<sup>th</sup> 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 St Melbourne (address)

being an officer, for the purposes of the *Corporations Act 2001* (Cth), of Powercor Australia Ltd ('Powercor'), do solemnly and sincerely declare that the response of Powercor 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 Powercor.

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 19<sup>th</sup> day of July 2010

[Signature] (Signature of person making declaration)

Before me: [Signature] (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. Powercor Australia 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 Powercor Australia in connection with the Draft Determination (**AER Draft Determination Documents**) because these documents are already in the AER's possession. However, Powercor Australia 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	Powercor AER Regulatory Information Notice Under Division 4 of Part 3 (Revised Regulatory Templates)		Yes
2	Powercor Post Tax Revenue Model		Yes
3	Powercor Roll Forward Model		Yes
4	Powercor Public Lighting Model		Yes
5	Powercor EBSS Model		Yes
6	Powercor S Factor True Up Model		Yes
7	Powercor Customer Capex Model	9	Yes
8	Powercor Customer Contribution Rate Model	9	Yes
9	Powercor Cost Escalation Model	7	Yes
10	Powercor Cost Forecast Model	6	Yes
11	Powercor Linked 2009-15 RIN Cost Templates		Yes
12	Powercor GSL Model	6	Yes
13	Powercor Superannuation Step Change Model	6	Yes
14	Powercor Changes to RIN Templates		Yes
15	Powercor RIN Allocators		Yes
16	Powercor Justification for no RIN Template Information		Yes
17	Powercor Regulatory Account Adjustments		Yes



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ID	Document name	Revised Regulatory Proposal reference	Confidential
18	Powercor Worked Example of Pass-through Factor Model	3	N
19	Powercor 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	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 Powercor Australia 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

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<b>ID</b>	<b>Document name</b>	<b>Revised Regulatory Proposal reference</b>	<b>Confidential</b>
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	Faruqi, 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 Powercor Australia 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	Powercor Australia, templates 10(a) to 10(g) submitted to the ESCV in the 2006-10 EDPR process, 12 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

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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 <a href="http://www.google.com/powermeter/about/about.html">http://www.google.com/powermeter/about/about.html</a>	4	No
59	'Become a Google PowerMeter partner' (webpage), available at <a href="http://www.google.com/powermeter/about/partnerships.html">http://www.google.com/powermeter/about/partnerships.html</a>	4	No
60	CurrentCost, CC128 ENVI Manual available at <a href="http://www.currentcost.com">www.currentcost.com</a>	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 <a href="http://www.abareconomics.com/publications_html/data/data/data.html#engHIS T">http://www.abareconomics.com/publications_html/data/data/data.html#engHIS T</a> ) 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 <a href="http://www.energyrating.gov.au/library/pubs/2008-energy-use-aust-res-sector-full.pdf">http://www.energyrating.gov.au/library/pubs/2008-energy-use-aust-res-sector-full.pdf</a> ), 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

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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 Powercor Australia for 2011-2015 EDPR (draft), 13 May 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

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ID	Document name	Revised Regulatory Proposal reference	Confidential
87	Owen, G and Ward, J (Sustainability First), Smart Tariffs and household demand response for Great Britain, March 2010	4	No
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 Powercor 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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<b>ID</b>	<b>Document name</b>	<b>Revised Regulatory Proposal reference</b>	<b>Confidential</b>
105	KPMG, Supplement to Report on Powercor Australia's service model, July 2010	5	Yes
106	Documents relied on and/or referred to in KPMG, Supplement to Report on Powercor Australia's service model, July 2010 and KPMG, The efficiencies of the Powercor service model, October 2009 (Attachment P0053 to the Initial Regulatory Proposal)	5	Yes
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 Cleve, 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



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ID	Document name	Revised Regulatory Proposal reference	Confidential
119	Powercor Australia Board Paper, Related Party Contract Recommendations, 17 November 2006	5	Yes
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	Powercor Australia'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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ID	Document name	Revised Regulatory Proposal reference	Confidential
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 Powercor 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
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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
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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	Powercor Australia, SCADA and network control capex material projects templates	9	No
158	AER, Queensland Draft Determination, Appendices	9	No
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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	Powercor Australia, 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	Powercor Australia, 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
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174	AER, SoRI	12, 13	No
175	AER, SoRI Final Decision	12, 13	No
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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
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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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189	Neville Hathaway, Imputation Credit Redemption: ATO data 1988-2008, July 2010	13	No
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191	Christopher L Skeels, Response to AER Questions, 21 September 2009	13	No
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195	Media release by Prime Minister entitled 'Breakthrough agreement with industry on improvements to resources taxation', 2 July 2010, <a href="http://www.pm.gov.au/node/6868">http://www.pm.gov.au/node/6868</a> ,	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
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202	Christopher L Skeels, Estimation of $\gamma$ , 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

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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 'Powercor 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



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222	Queensland Competition Authority, Final Determination on the Regulation of Electricity Distribution 2005-10	17	No
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 Powercor Australia'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, <i>Sector Commentary, Manufacturing &amp; Ops</i> , 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

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239	Servicestream, Presentation - Working Together CitiPower/Powercor Contract Variations October 2009	19	Yes
240	Powercor Australia'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	Energy Safe Victoria, Exemptions granted to Powercor Australia under reg. 10 of the Electricity Safety (Electric Line Clearance Regulations) 2005	14	No
250	Powercor Australia, Business Case for Enhanced Asset Management of At Risk Townships protection plans, 15 July 2010	6	Yes
251	Cost build up model for At Risk Townships program step change	6	Yes
252	PB, Overhead conductor replacement investment strategy, May 2010	9	No
253	Powercor Australia, Review of Overhead Conductor Strategy for CitiPower and Powercor, 29 January 2010	9	No
254	Powercor Australia, Minutes to the Capital Investment Committee meeting, 11 August 2009	9	Yes
255	Powercor Australia, Protection Equipment (Relays) Asset Management Plan, 14 May 2010	9	No
256	Consulting and Power, Draft Report No: 200927, Commentary on the potential lives of bare high voltage electricity conductors for Powercor Australia, 23 April 2010	9	Yes

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257	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, Powercor Australia 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*

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- $P'_{t-1}$  (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  $\phi$ ) is calculated in accordance with section 3 for *regulatory year t*

$Rf_t$  (in  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) is a correction factor to account for any under or over recovery of actual passthrough revenue for *regulatory year t-1*

$KPy_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.1 for *regulatory year t*

$KPz_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2 for *regulatory year t*

$KP_{t-1}$  (in  $\phi$ ) 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  $\phi$ ) is a correction factor for *regulatory year t-1*

$PRe_{t-1}$  (in  $\phi$ ) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*

$PCe_{t-1}$  (in  $\phi$ ) 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.

$$PRe_t = \left( \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij} \right) \times P'_t$$

Where:

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

$PRe_t$  (in  $\phi$ ) 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*

$p_t^{ij}$  is calculated in accordance with section 4.1 for *regulatory year t*

$q_t^{ij}$  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.

$$KPz_t = \{(P Ra_{t-2} - P Re_{t-2}) - (P Ca_{t-2} - P Ce_{t-2})\} \times (1 + \text{pretax } WACC_D) \times (1 + CPI_{t-1})$$

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  $\phi$ ) is a correction amount for the difference between amounts calculated in section 3.1.1 in *regulatory year t-1* and actual values

$P Ra_{t-2}$  (in  $\phi$ ) is calculated in accordance with section 3.1.2.1 in *regulatory year t-2*

$P Re_{t-2}$  (in  $\phi$ ) is the figure used for  $P Re_{t-1}$  when calculating  $KPy_t$  under section 3.1.1 for *regulatory year t-1*

$P Ca_{t-2}$  (in  $\phi$ ) 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*

$P Ce_{t-2}$  (in  $\phi$ ) is the amount calculated for  $P Ce_{t-1}$  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<sub>D</sub>* is as set out in section 3.1

#### 3.1.2.1. Calculation of $P Ra_t$

$P Ra_t$  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.

$$P Ra_t = Ra_t - Ra''_t$$

Where

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

$PRa_t$  (in  $\phi$ ) is the calculated revenue earned by the distribution business from the P factor in *regulatory year t*

$Ra_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*

$Ra''_t$  (in  $\phi$ ) 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  $\phi$ ) is the calculated Weighted Average Price Cap (WAPC) revenue earned in *regulatory year t*

$p_t^{ij}$  is the distribution tariff rate for component  $j$  of distribution tariff  $i$  in regulatory year  $t$

$q_t^{ij}$  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  $\phi$ ) is the calculated revenue earned without  $P'$  factor in *regulatory year t*

$Ra_t$  (in  $\phi$ ) 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.

$$Rf_t = \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij}$$

Where

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

$Rf_t$  (in  $\phi$ ) is the forecast revenue expected to be earned without the  $P_t$  in the *regulatory year t*

$p_t^{ij}$  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*

$q_t^{ij}$  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**

$p_t^{ij}$  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.

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$$P_t^{ij} = P_{t-1}^{ij} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t)$$

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"*

$P_t^{ij}$  is the theoretical price of the distribution tariff rate in *regulatory year t* without the  $P_t$  for each tariff component  $j$  of tariff  $i$

$P_{t-1}^{ij}$  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<sub>t</sub>*) 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<sub>t</sub>*) 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<sub>t</sub>* 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'<sub>t</sub>* is calculated in accordance with section 2 for *regulatory year t*

*TRC'<sub>t-1</sub>* (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'<sub>t</sub>* 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  $\phi$ ) is calculated in accordance with section 3 for *regulatory year t*

$Rf_t$  (in  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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.

$$KTRC_t = (KTRC_{y_t} + KTRC_{z_t} + KTRC_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

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  $\phi$ ) is a correction factor to account for any under or over recovery of actual transmission-related costs revenue for *regulatory year t-1*

$KTRC_{y_t}$  (in  $\phi$ ) is calculated in accordance with section 3.1.1 for *regulatory year t*

$KTRC_{z_t}$  (in  $\phi$ ) is calculated in accordance with section 3.1.2 for *regulatory year t*

$KTRC_{t-1}$  (in  $\phi$ ) is the figure calculated for  $KTRC_t$  for *regulatory year t-1*

*pretax WACC<sub>D</sub>* 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 $KTRC_{y_t}$

$KTRC_{y_t}$  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.

$$KTRC_{y_t} = TRCRe_{t-1} - TRCCe_{t-1}$$

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"*

$KTRC_y_t$  (in  $\phi$ ) is a correction factor for *regulatory year t-1*

$TRCRe_{t-1}$  (in  $\phi$ ) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*

$TRCCe_{t-1}$  (in  $\phi$ ) 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.

$$TRCRe_t = \left( \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij} \right) \times TRC'_t$$

Where:

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

$TRCRe_t$  (in  $\phi$ ) 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*

$p_t^{ij}$  is calculated in accordance with section 4.1 for *regulatory year t*

$q_t^{ij}$  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.

$$KTRCz_t = \{(TRCRA_{t-2} - TRCRe_{t-2}) - (TRCCa_{t-2} - TRCCe_{t-2})\} \times (1 + \text{pretaxWACC}_D) \times (1 + CPI_{t-1})$$

Where:

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<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
<i>regulatory year "t-1"</i>	is the regulatory year immediately preceding <i>regulatory year "t"</i>
<i>regulatory year "t-2"</i>	is the regulatory year immediately preceding <i>regulatory year "t-1"</i>
<i>KTRCz<sub>t</sub></i>	(in $\phi$ ) is a correction amount for the difference between amounts calculated in section 3.1.1 in <i>regulatory year t-1</i> and actual values
<i>TRCRA<sub>t-2</sub></i>	(in $\phi$ ) is calculated in accordance with section 3.1.2.1 in <i>regulatory year t-2</i>
<i>TRCRe<sub>t-2</sub></i>	(in $\phi$ ) is the figure used for <i>TRCRe<sub>t-1</sub></i> when calculating <i>KTRCy<sub>t</sub></i> under section 3.1.1 for <i>regulatory year t-1</i>
<i>TRCCa<sub>t-2</sub></i>	(in $\phi$ ) 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 <i>regulatory year t-2</i>
<i>TRCCe<sub>t-2</sub></i>	(in $\phi$ ) is the amount calculated for <i>TRCCe<sub>t-1</sub></i> when calculating <i>KTRCy<sub>t</sub></i> under section 3.1.1 for <i>regulatory year t-1</i>
<i>CPI<sub>t-1</sub></i>	is as set out in section 3.1
<i>pretax WACC<sub>D</sub></i>	is as set out in section 3.1

### **3.1.2.1. Calculation of *TRCRA<sub>t</sub>***

*TRCRA<sub>t</sub>* 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

<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
<i>TRCRA<sub>t</sub></i>	(in $\phi$ ) is the calculated revenue earned by the distribution business from the <i>TRC</i> factor in <i>regulatory year t</i>

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$Ra_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*

$Ra''_t$  (in  $\phi$ ) 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  $\phi$ ) is the calculated Weighted Average Price Cap (WAPC) revenue earned in *regulatory year t*

$p_t^{ij}$  is the distribution tariff rate for component  $j$  of distribution tariff  $i$  in regulatory year  $t$

$q_t^{ij}$  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 $\text{€}$ ) is the calculated revenue earned without $TRC'$ factor in <i>regulatory year t</i>
$Ra_t$	(in $\text{€}$ ) is calculated in accordance with section 3.1.2.1.1 for <i>regulatory year t</i>
$TRC'_t$	is calculated in accordance with section 2 for <i>regulatory year t</i>

#### 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.

$$Rf_t = \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij}$$

Where

<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
$Rf_t$	(in $\text{€}$ ) is the forecast revenue expected to be earned without the $TRC_t$ in the <i>regulatory year t</i>
$p_t^{ij}$	is the distribution tariff rate for component $j$ of distribution tariff $i$ in regulatory year $t$ calculated in accordance with section 4.1 for <i>regulatory year t</i>
$q_t^{ij}$	is the forecast quantity of distribution tariff component $j$ of distribution tariff $i$ in <i>regulatory year t</i>

##### 4.1. Price without current year $TRC$ factor

$p_t^{ij}$  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.

$$p_t^{ij} = p_{t-1}^{ij} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \times (1 + P_t)$$

Where:

<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
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*regulatory year "t-1"* is the regulatory year immediately preceding *regulatory year "t"*

$p_t^{ij}$  is the theoretical price of the distribution tariff rate in *regulatory year t* without the  $TRC_i$  for each tariff component  $j$  of tariff  $i$

$p_{t-1}^{ij}$  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  $\phi$ ) is calculated in accordance with section 3 for *regulatory year t*

$Rf_t$  (in  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) is calculated in accordance with section 3.1.1 for *regulatory year t*

$KTz_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2 for *regulatory year t*

$KT_{t-1}$  (in  $\phi$ ) is the figure calculated for  $KT_t$  for *regulatory year t-1*

*pretax WACC<sub>D</sub>* 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

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*regulatory year "t-1"* is the regulatory year immediately preceding *regulatory year "t"*

$KTy_t$  (in  $\phi$ ) is a correction factor for *regulatory year t-1*

$TRe_{t-1}$  (in  $\phi$ ) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*

$TCE_{t-1}$  (in  $\phi$ ) 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.

$$TRe_t = \left( \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij} \right) \times T'_t$$

Where:

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

$TRe_t$  (in  $\phi$ ) 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*

$p_t^{ij}$  is calculated in accordance with section 4.1 for *regulatory year t*

$q_t^{ij}$  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.

$$KTz_t = \{(TRa_{t-2} - TRe_{t-2}) - (Tca_{t-2} - Tce_{t-2})\} \times (1 + \text{pretaxWACC}_D) \times (1 + CPI_{t-1})$$

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Where:

<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
<i>regulatory year "t-1"</i>	is the regulatory year immediately preceding <i>regulatory year "t"</i>
<i>regulatory year "t-2"</i>	is the regulatory year immediately preceding <i>regulatory year "t-1"</i>
$KTz_t$	(in $\phi$ ) is a correction amount for the difference between amounts calculated in section 3.1.1 in <i>regulatory year t-1</i> and actual values
$TRa_{t-2}$	(in $\phi$ ) is calculated in accordance with section 3.1.2.1 in <i>regulatory year t-2</i>
$TRe_{t-2}$	(in $\phi$ ) is the figure used for $TRe_{t-1}$ when calculating $KTy_t$ under section 3.1.1 for <i>regulatory year t-1</i>
$TCa_{t-2}$	(in $\phi$ ) 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 <i>regulatory year t-2</i>
$TCe_{t-2}$	(in $\phi$ ) is the amount calculated for $TCe_{t-1}$ when calculating $KTy_t$ under section 3.1.1 for <i>regulatory year t-1</i>
$CPI_{t-1}$	is as set out in section 3.1
<i>pretax WACC<sub>D</sub></i>	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

<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
$TRa_t$	(in $\phi$ ) is the calculated revenue earned by the distribution business from the <i>T</i> factor in <i>regulatory year t</i>

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$Ra_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*

$Ra''_t$  (in  $\phi$ ) 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  $\phi$ ) is the calculated Weighted Average Price Cap (WAPC) revenue earned in *regulatory year t*

$p_t^{ij}$  is the distribution tariff rate for component  $j$  of distribution tariff  $i$  in regulatory year  $t$

$q_t^{ij}$  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 $\text{€}$ ) is the calculated revenue earned without $T$ factor in <i>regulatory year t</i>
$Ra_t$	(in $\text{€}$ ) is calculated in accordance with section 3.1.2.1.1 for <i>regulatory year t</i>
$T'_t$	is calculated in accordance with section 2 for <i>regulatory year t</i>

#### 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.

$$Rf_t = \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij}$$

Where

<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
$Rf_t$	(in $\text{€}$ ) is the forecast revenue expected to be earned without the $T_t$ in the <i>regulatory year t</i>
$p_t^{ij}$	is the distribution tariff rate for component $j$ of distribution tariff $i$ in regulatory year $t$ calculated in accordance with section 4.1 for <i>regulatory year t</i>
$q_t^{ij}$	is the forecast quantity of distribution tariff component $j$ of distribution tariff $i$ in <i>regulatory year t</i>

##### 4.1. Price without current year $T$ factor

$p_t^{ij}$  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.

$$p_t^{ij} = p_{t-1}^{ij} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \times (1 + P_t) \times (1 + TRC_t)$$

Where:

<i>regulatory year "t"</i>	is the regulatory year in respect of which the calculation is being made
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*regulatory year "t-1"* is the regulatory year immediately preceding *regulatory year "t"*

$p_t^{ij}$  is the theoretical price of the distribution tariff rate in *regulatory year t* without the  $P_t$  for each tariff component  $j$  of tariff  $i$

$p_{t-1}^{ij}$  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<sub>t</sub>*) 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<sub>t</sub>*) 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<sub>t</sub>* 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'<sub>t</sub>* is calculated in accordance with section 2 for *regulatory year t*

*KAY'<sub>t-1</sub>* (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'<sub>t</sub>* determined in the *regulatory year t-1*

### **2. Calculation of *KAY'<sub>t</sub>***

*KAY'<sub>t</sub>* 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  $\phi$ ) is calculated in accordance with section 3 for *regulatory year t*

$Rf_t$  (in  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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.

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$$KKAY_t = (KKAY_y_t + KKAY_z_t + KKAY_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

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  $\phi$ ) is a correction factor to account for any under or over recovery of actual K-Factor True-up revenue for *regulatory year t-1*

$KKAY_y_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.1 for *regulatory year t*

$KKAY_z_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2 for *regulatory year t*

$KKAY_{t-1}$  (in  $\phi$ ) is the figure calculated for  $KKAY_t$  for *regulatory year t-1*

*pretax WACC<sub>D</sub>* 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 $KKAY_y_t$

$KKAY_y_t$  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.

$$KKAY_y_t = KAYRe_{t-1} - KAYCe_{t-1}$$

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"*

$KKAY_y_t$  (in  $\phi$ ) is a correction factor for *regulatory year t-1*



$KAYRe_{t-1}$  (in  $\phi$ ) is calculated in accordance with section 3.1.1.1 for *regulatory year t-1*

$KAYCe_{t-1}$  (in  $\phi$ ) 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.

$$KAYRe_t = \left( \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij} \right) \times KAY'_t$$

Where:

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

$KAYRe_t$  (in  $\phi$ ) 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*

$p_t^{ij}$  is calculated in accordance with section 4.1 for *regulatory year t*

$q_t^{ij}$  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.

$$KKAYz_t = \{(KAYRa_{t-2} - KAYRe_{t-2}) - (KAYCa_{t-2} - KAYCe_{t-2})\} \times (1 + \text{pretaxWACC}_D) \times (1 + CPI_{t-1})$$

Where:

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

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*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  $\phi$ ) 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  $\phi$ ) is calculated in accordance with section 3.1.2.1 in *regulatory year t-2*

$KAYRe_{t-2}$  (in  $\phi$ ) 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  $\phi$ ) 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  $\phi$ ) 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<sub>D</sub>* 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  $\phi$ ) is the calculated revenue earned by the distribution business from the *KAY* factor in *regulatory year t*

$Ra_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2.1.1 for *regulatory year t*

$Ra'_t$  (in  $\phi$ ) 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  $\phi$ ) is the calculated Weighted Average Price Cap (WAPC) revenue earned in regulatory year  $t$

$p_t^{ij}$  is the distribution tariff rate for component  $j$  of distribution tariff  $i$  in regulatory year  $t$

$q_t^{ij}$  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  $\phi$ ) is the calculated revenue earned without  $KAY'$  factor in regulatory year  $t$

$Ra_t$  (in  $\phi$ ) is calculated in accordance with section 3.1.2.1.1 for regulatory year  $t$

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$KAY_t$  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.

$$Rf_t = \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} \times q_t^{ij}$$

Where

*regulatory year "t"* is the regulatory year in respect of which the calculation is being made

$Rf_t$  (in  $\phi$ ) is the forecast revenue expected to be earned without the  $KAY_t$  in the *regulatory year t*

$p_t^{ij}$  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*

$q_t^{ij}$  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

$p_t^{ij}$  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.

$$p_t^{ij} = p_{t-1}^{ij} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \times (1 + P_t) \times (1 + TRC_t) \times (1 + T_t)$$

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"*

$p_t^{ij}$  is the theoretical price of the distribution tariff rate in *regulatory year t* without the  $KAY_t$  for each tariff component  $j$  of tariff  $i$

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$p_{t-1}^j$	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 <i>regulatory year t</i>
$X_t$	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 <i>regulatory year t</i>
$TRC_t$	is transmission-related costs for <i>regulatory year t</i>
$T_t$	is S-Factor true up for <i>regulatory year t</i>

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**Appendix 4.1 – Powercor Australia’s revised spatial maximum demand forecasts (following reconciliation with NIEIR’s system level maximum demand forecasts)**

		2011	2012	2013	2014	2015
<b>Total</b>						
Sum of ZSS forecast		2457.2	2531.8	2627.4	2722.0	2823.0
Difference from Initial Regulatory Proposal (MW)		0.0	7.3	50.7	96.7	140.6
Difference (%)		0.0%	0.3%	1.9%	3.6%	5.0%
<b>Targeted zone substations</b>						
BAN	Initial Regulatory Proposal	92.3	88.3	89.5	90.8	92.1
	Revised Regulatory Proposal	92.3	88.7	92.5	96.6	100.7
BAS	Initial Regulatory Proposal	92.3	88.3	89.5	90.8	92.1
	Revised Regulatory Proposal	74.6	84.9	89.8	94.7	99.4
BGO	Initial Regulatory Proposal	54.2	55.1	47.4	48.1	49.0
	Revised Regulatory Proposal	54.2	55.4	49.2	51.3	53.7
CLC	Initial Regulatory Proposal	45.9	47.4	48.3	49.3	50.2
	Revised Regulatory Proposal	45.9	47.7	48.9	50.2	51.6
CME	Initial Regulatory Proposal	39.3	40.1	41.0	41.9	42.8
	Revised Regulatory Proposal	39.3	40.3	41.5	42.7	44.0
CRO	Initial Regulatory Proposal	31.1	31.4	31.8	32.1	32.4
	Revised Regulatory Proposal	31.1	31.6	32.1	32.7	33.3
DDL	Initial Regulatory Proposal	54.7	58.3	60.4	64.2	66.0
	Revised Regulatory Proposal	54.7	58.5	62.3	66.0	69.7
EHK	Initial Regulatory Proposal	53.5	54.4	55.2	56.1	57.0
	Revised Regulatory Proposal	53.5	54.7	57.5	60.6	63.5
FNS	Initial Regulatory Proposal	44.7	46.8	48.7	49.3	50.2
	Revised Regulatory Proposal	44.7	47.1	50.8	53.3	55.9
GCY	Initial Regulatory Proposal	42.3	42.7	43.1	43.5	45.7
	Revised Regulatory Proposal	42.3	42.9	44.5	46.2	47.9
GL	Initial Regulatory Proposal	57.0	57.4	58.3	59.2	59.7
	Revised Regulatory Proposal	57.0	57.7	60.8	64.0	66.5
GLE	Initial Regulatory Proposal	49.5	50.3	53.1	51.8	52.3
	Revised Regulatory Proposal	49.5	50.6	53.7	52.8	53.8
HSM	Initial Regulatory Proposal	49.2	49.9	50.6	51.3	52.0



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	Revised Regulatory Proposal	49.2	50.2	52.3	54.5	56.7
LV	Initial Regulatory Proposal	79.3	83.8	87.0	90.4	93.9
	Revised Regulatory Proposal	79.3	84.2	90.6	96.9	103.7
LVN	Initial Regulatory Proposal	73.7	75.8	78.0	80.3	82.6
	Revised Regulatory Proposal	73.7	76.2	81.3	86.7	91.9
MDA	Initial Regulatory Proposal	52.8	54.2	55.4	56.6	57.8
	Revised Regulatory Proposal	52.8	54.5	57.2	60.0	62.7
MLN	Initial Regulatory Proposal	51.4	52.9	54.5	56.2	57.9
	Revised Regulatory Proposal	51.4	53.2	56.8	60.7	64.4
SA	Initial Regulatory Proposal	89.1	91.3	93.6	96.0	98.4
	Revised Regulatory Proposal	89.1	91.7	97.5	103.6	109.4
SHN	Initial Regulatory Proposal	38.3	38.8	39.3	39.9	40.4
	Revised Regulatory Proposal	38.3	39.0	40.6	42.3	44.1
SSE	Initial Regulatory Proposal	45.1	49.0	57.2	58.5	72.8
	Revised Regulatory Proposal	45.1	49.2	59.3	62.8	80.2
STN	Initial Regulatory Proposal	48.9	52.8	53.8	54.9	56.0
	Revised Regulatory Proposal	48.9	53.0	55.6	58.2	61.0
SU	Initial Regulatory Proposal	84.2	84.5	80.8	83.9	76.8
	Revised Regulatory Proposal	84.2	84.9	84.5	90.8	85.9
WBE	Initial Regulatory Proposal	85.6	87.9	90.3	92.8	95.4
	Revised Regulatory Proposal	85.6	88.3	93.4	98.8	104.3
WND	Initial Regulatory Proposal	52.6	54.4	56.4	58.4	60.6
	Revised Regulatory Proposal	52.6	54.7	57.1	59.6	62.2
WPD	Initial Regulatory Proposal	76.5	81.9	86.9	89.0	91.8
	Revised Regulatory Proposal	76.5	82.2	87.9	92.9	97.4

## **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 Powercor Australia'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 prudence criterion;
- the proper construction and application of the efficiency criterion; and
- the AER's discretion to balance the competing efficiency and prudence criteria.

Powercor Australia'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, Powercor Australia's views on the proper construction and application of the prudence 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 prudence 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 prudence 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 prudence criterion include the group structure of the DNSP, it does not follow that the prudence 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 Powercor Australia 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*,<sup>1</sup> 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;<sup>2</sup> and
  - the Tribunal concluded in *Application of Energy Australia and Others* that the NEO and the revenue and pricing principles require

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<sup>1</sup> [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].

<sup>2</sup> NEL, section 16; [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [14] & [74].

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that the regulatory setting of prices *'err on the side of allowing at least the recovery of efficient costs'*.<sup>3</sup>

### **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:<sup>4</sup>

*'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. Powercor Australia submits that consideration of this statutory purpose or drafting intent is essential to the proper construction of the prudency criterion. Powercor Australia reminds the AER that the Rules are to be given a purposive rather than a literal interpretation.<sup>5</sup>

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<sup>3</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [78].

<sup>4</sup> AER, Draft Determination, p179.

<sup>5</sup> 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.

Powercor Australia 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.<sup>6</sup> 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

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<sup>6</sup> 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 prudence 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 prudence 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.<sup>7</sup> It further observed that:<sup>8</sup>

*'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'*.<sup>9</sup>

Powercor Australia accepts that the efficiency criterion, properly construed and applied, necessitates an inquiry into pricing outcomes in a workably competitive market. However, Powercor Australia disagrees with the AER that it follows that historical efficiencies realised by another entity in the group to which the DNSP

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<sup>7</sup> AER, Draft Determination, p182.

<sup>8</sup> AER, Draft Determination, p182, in footnote 25.

<sup>9</sup> AER, Draft Determination, p182.



belongs do not warrant payment of an amount in excess of the contractor's directly incurred costs.

Powercor Australia 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*,<sup>10</sup> 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:<sup>11</sup>

*'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]

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<sup>10</sup> [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [119]-[124].

<sup>11</sup> [2006] ACompT 8 (Attachment 96 to this Revised Regulatory Proposal) at [122]-[124].

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The Tribunal's decision establishes that the benchmark against which the efficiency of Powercor Australia's expenditure under outsourcing arrangements should be assessed is that of stand-alone, in-house service provision.

### **Balancing the efficiency criterion and the prudence criterion**

There is a tension between the efficiency and the prudence 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*.<sup>12</sup> 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 prudence criteria. However, the AER's discretion to balance the efficiency and prudence criteria is not unlimited.

Powercor Australia considers that, in striking a reasonable balance between the efficiency criterion and the prudence 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 prudence 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 prudence 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.<sup>13</sup> It is this obligation that necessitates that the balance the AER strikes between the efficiency and prudence 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*'.<sup>14</sup> 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*'.<sup>15</sup>

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*

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<sup>12</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [140]-[142].

<sup>13</sup> NEL, section 16.

<sup>14</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [14].

<sup>15</sup> [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*'.<sup>16</sup> It then gave specific consideration to construing section 7A(2) of the NEL as follows:<sup>17</sup>

*'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 prudence criterion.

Powercor Australia's views on the AER's discretion to balance the efficiency and prudence 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 prudence 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*'.<sup>18</sup> The Tribunal recognised these expert opinions as '*non-controversial*' in *Application of Energy Australia and Others*.<sup>19</sup>

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<sup>16</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [76].

<sup>17</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [77] & [78].

<sup>18</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [141].

<sup>19</sup> [2009] ACompT 8 (Attachment 97 to this Revised Regulatory Proposal) at [142].

**Confidential Appendix 5.2 - Analysis of Powercor Australia's Corporate Services Agreement with CHED Services and Network Services Agreement with PNS**

Powercor Australia claims confidentiality over this Appendix 5.2 in its entirety.

[REDACTED]	[REDACTED]	[REDACTED]
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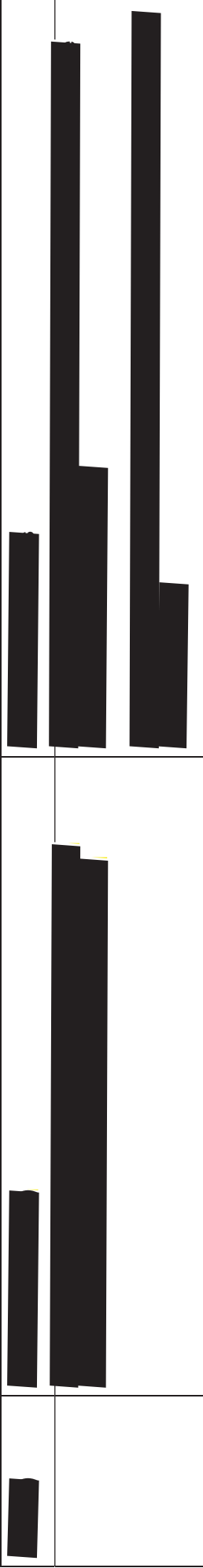
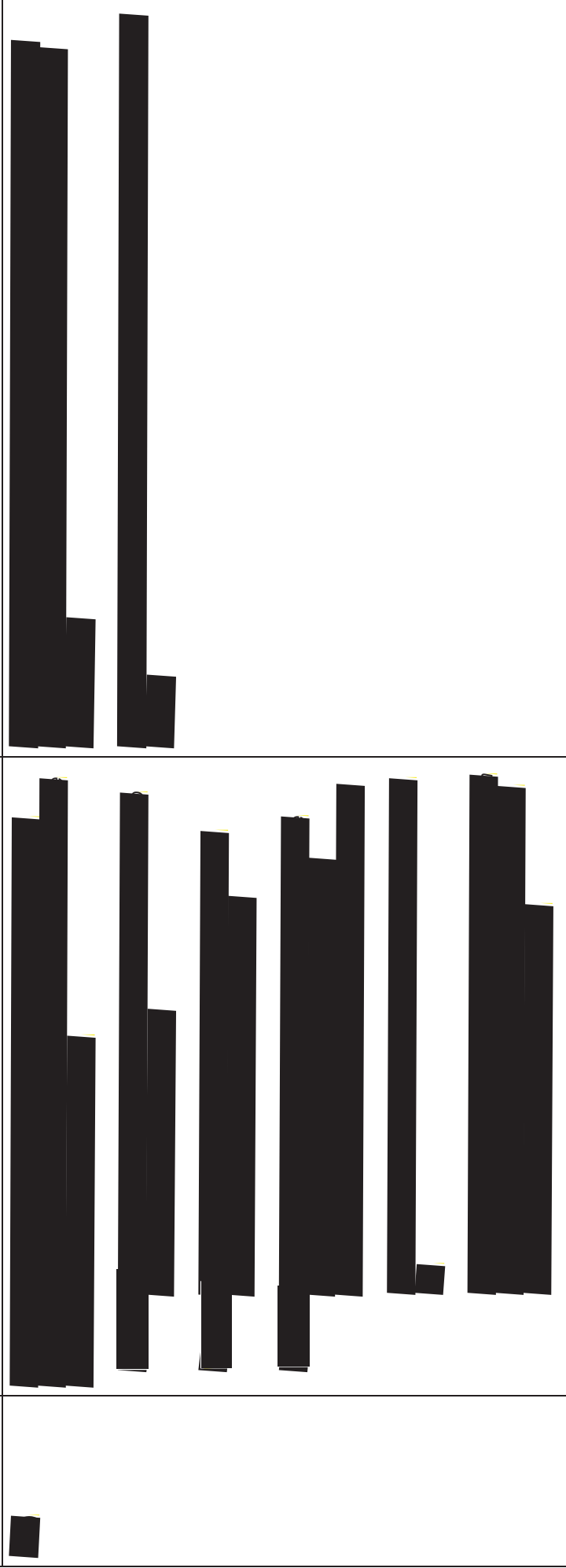




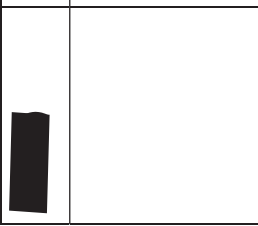
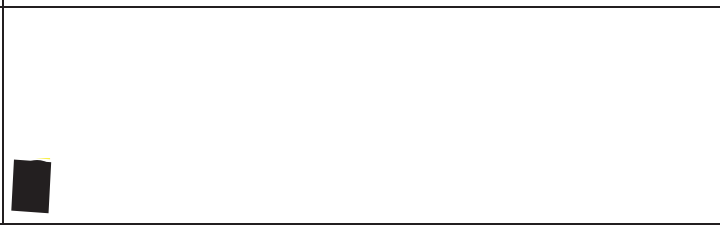
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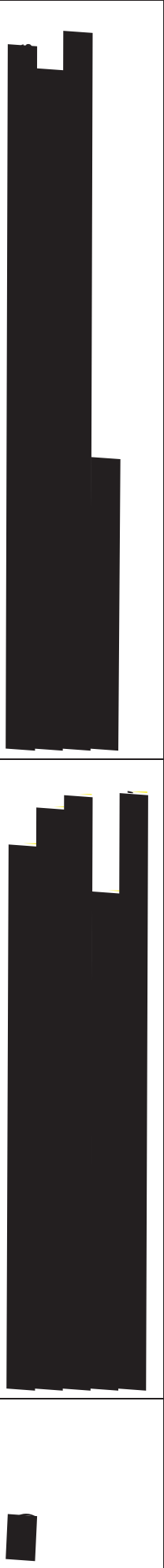
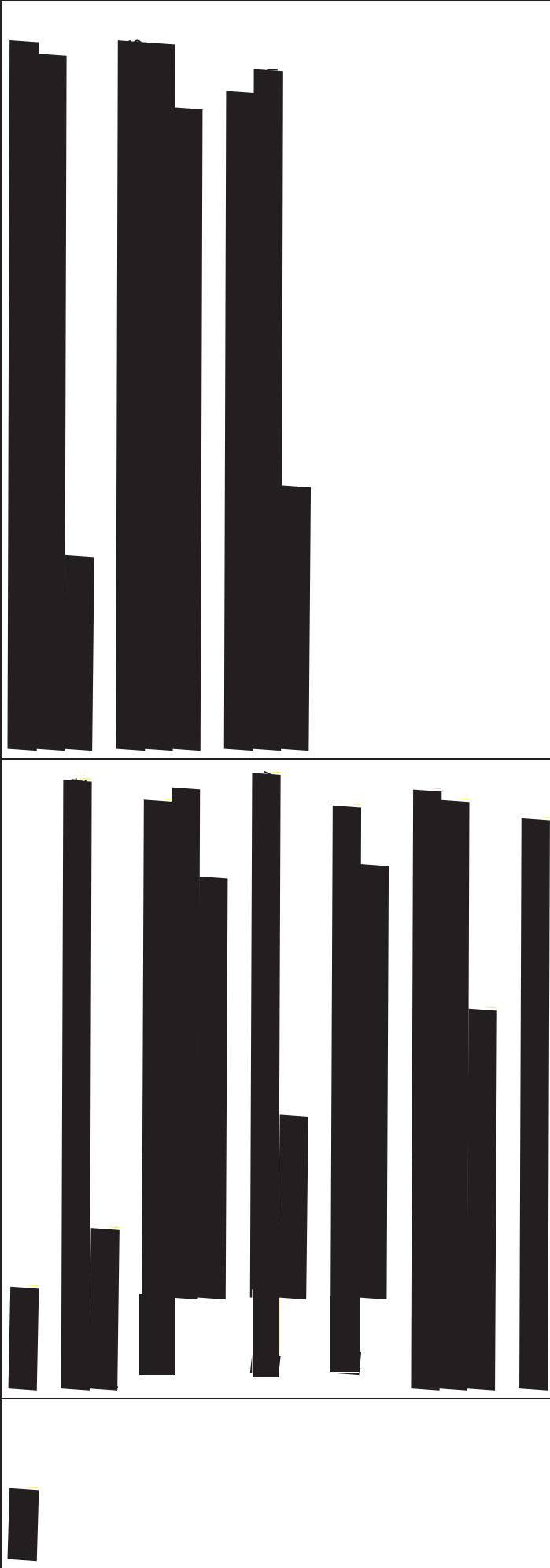


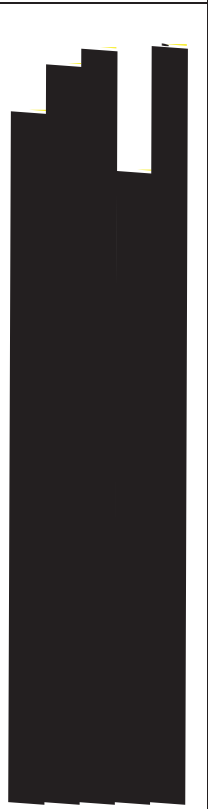
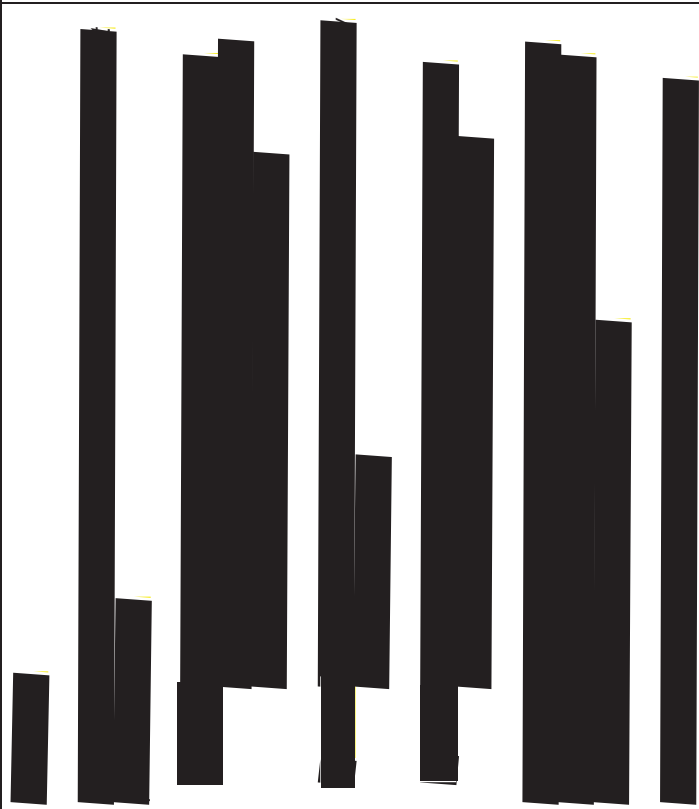
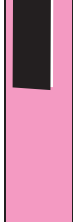

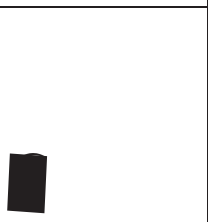
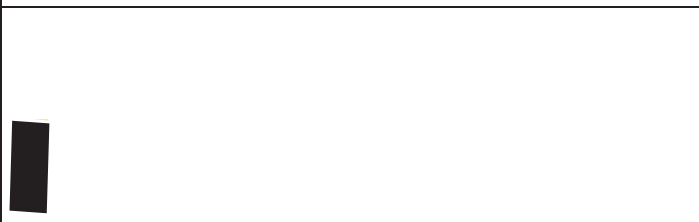



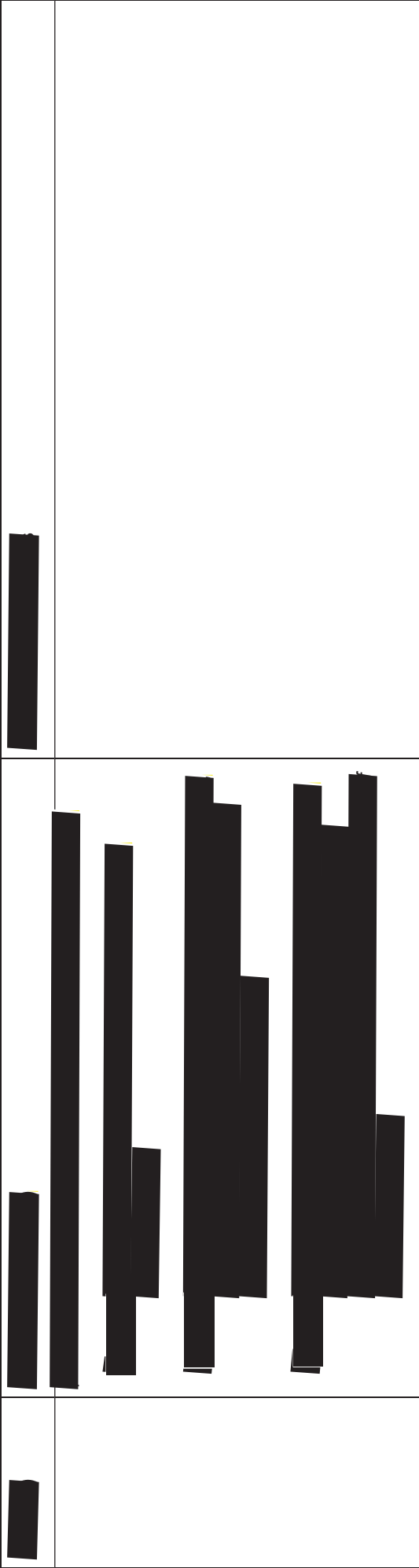
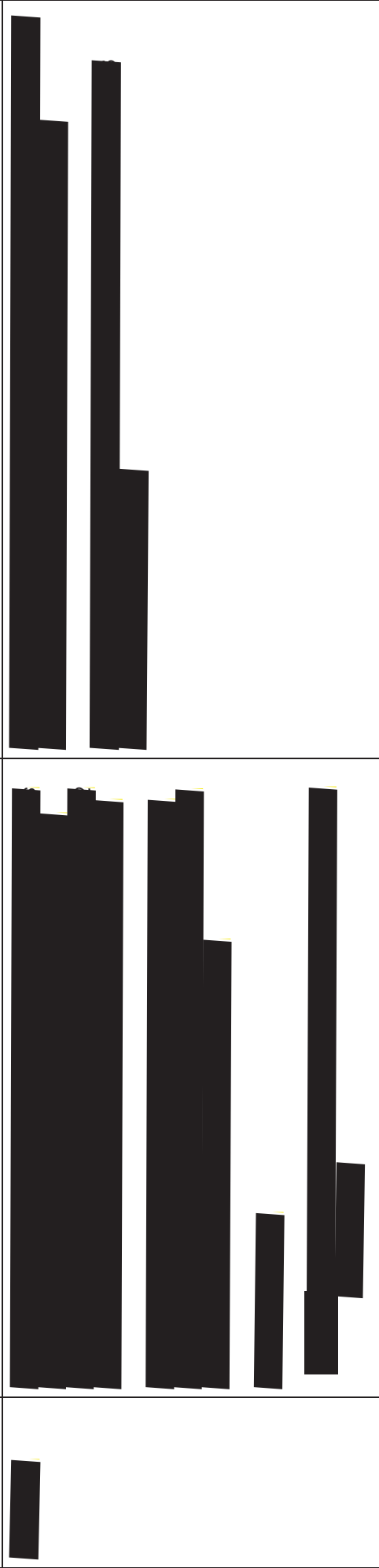
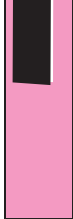
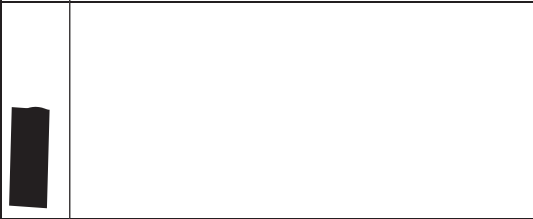
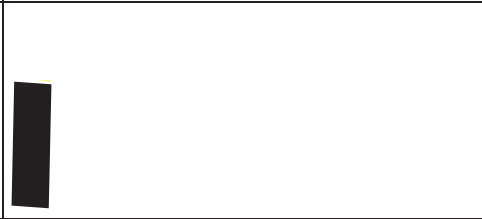

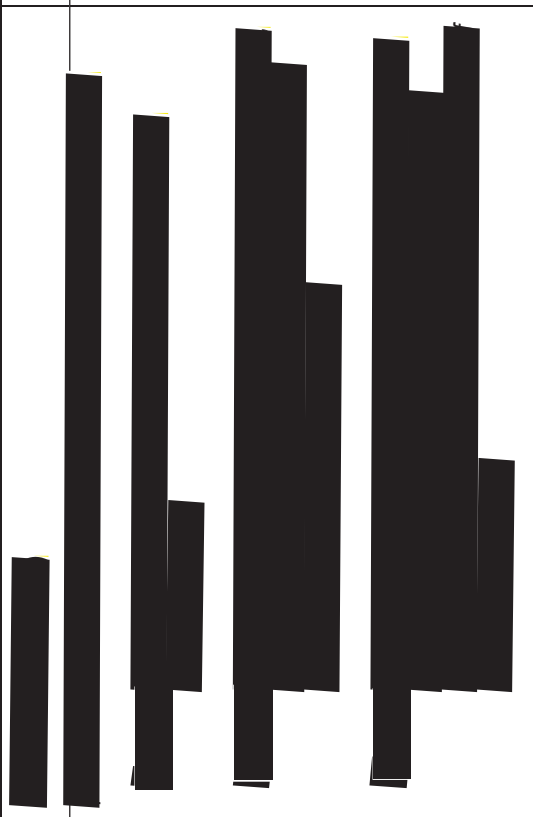


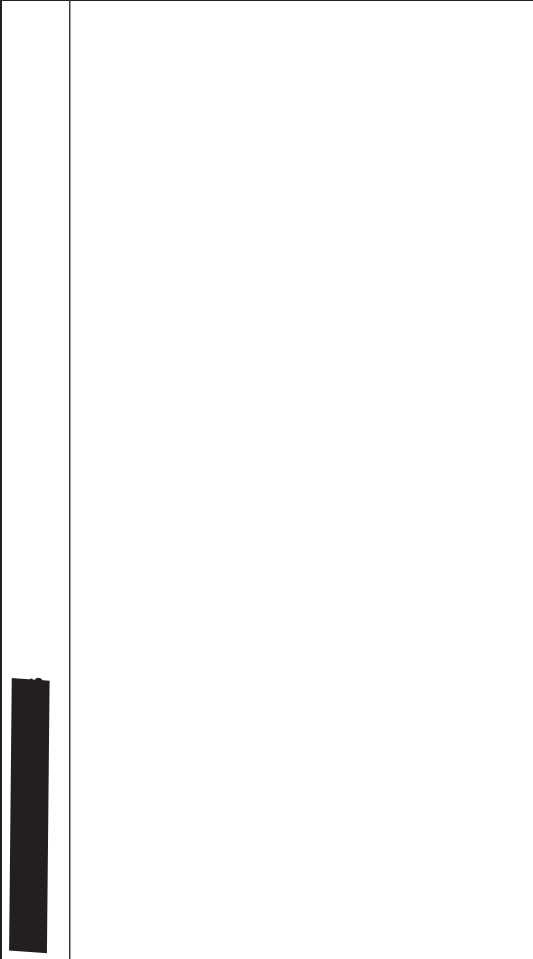







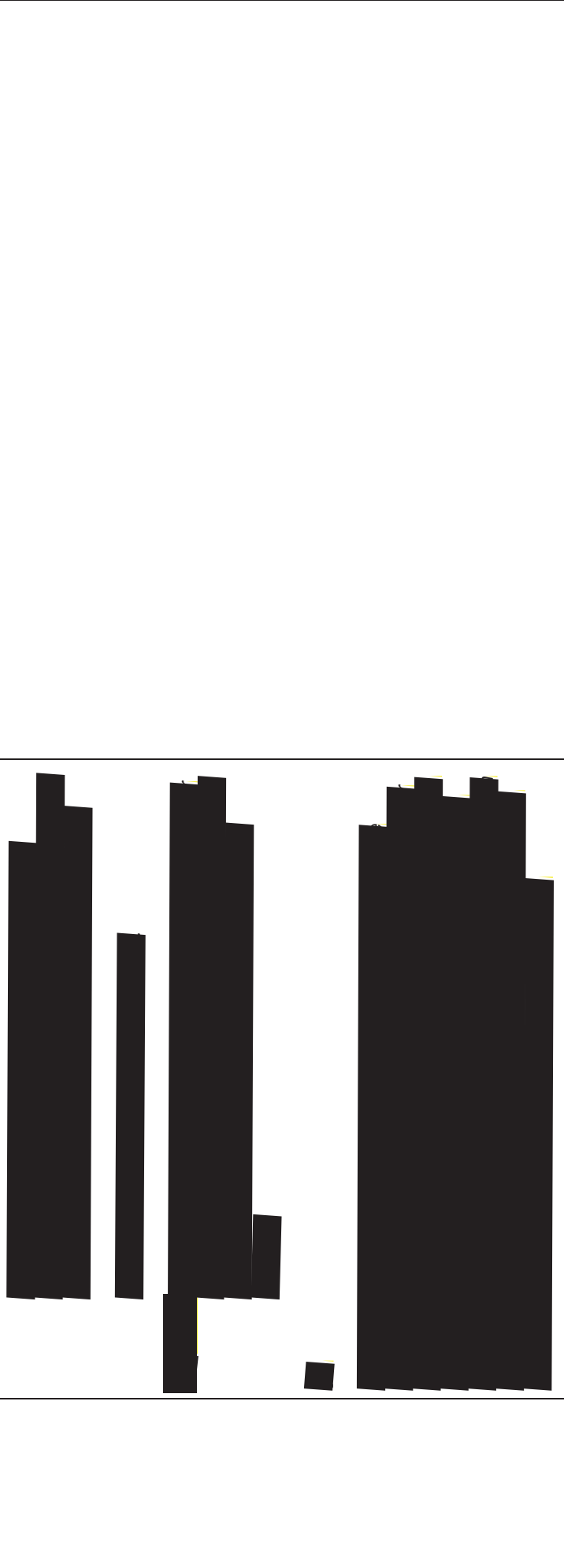
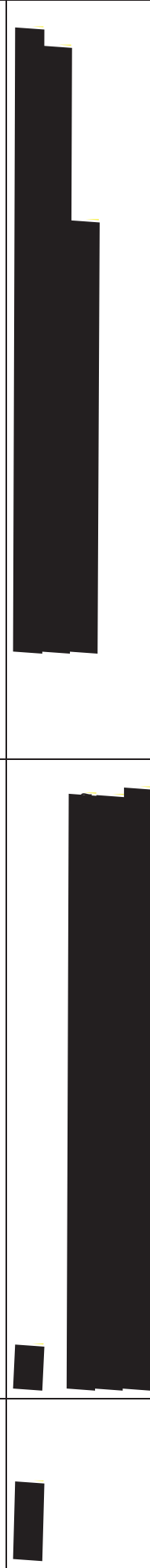



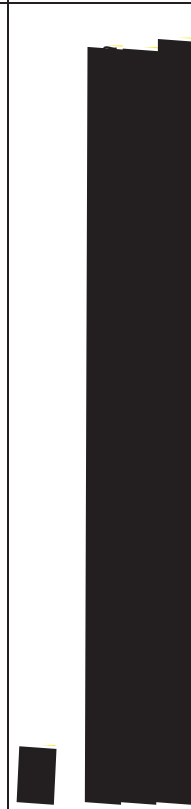
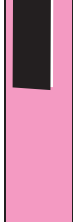

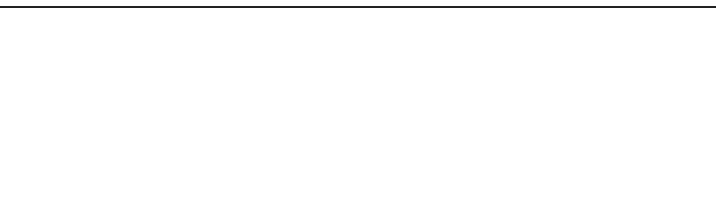





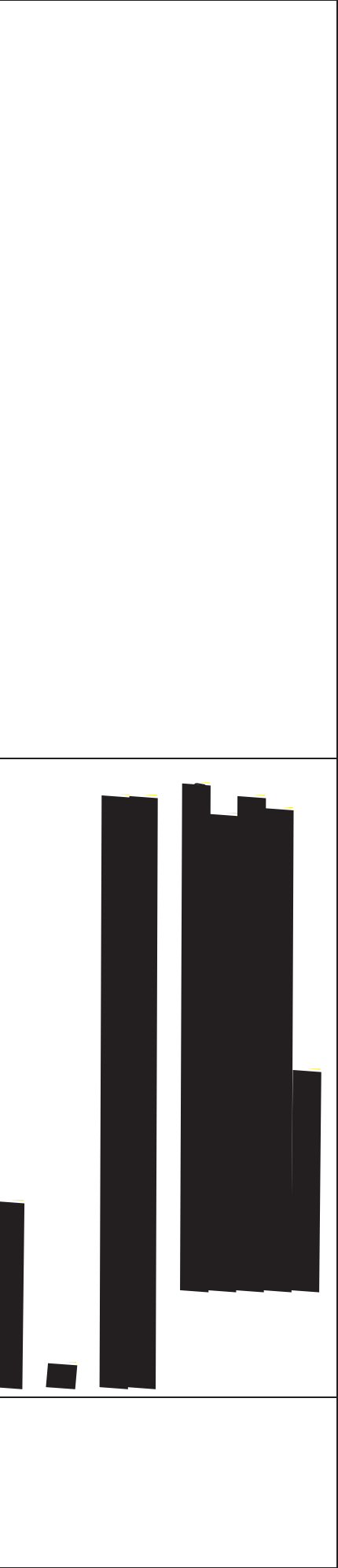
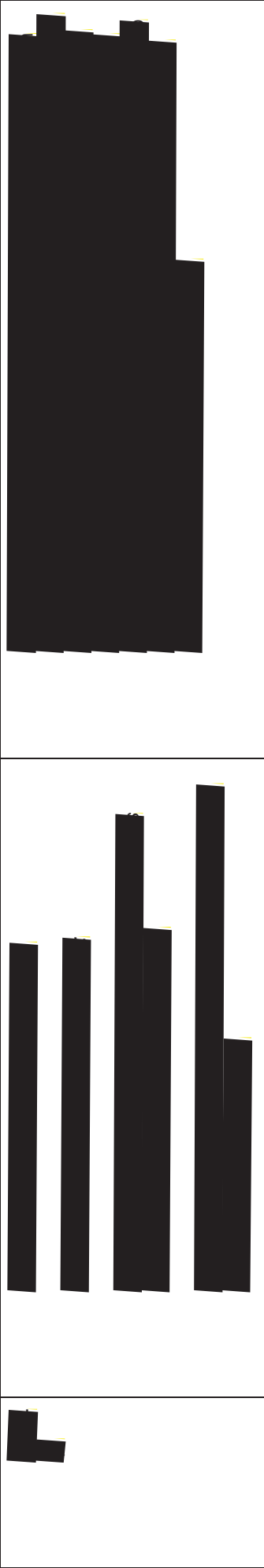
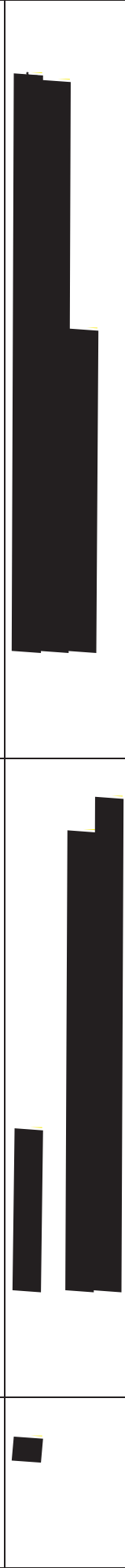





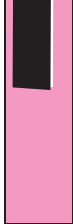

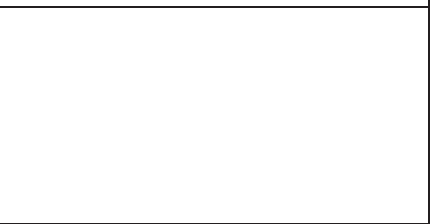

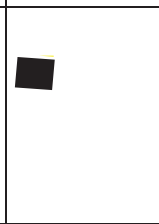
			
			
			


















		
		
		
		


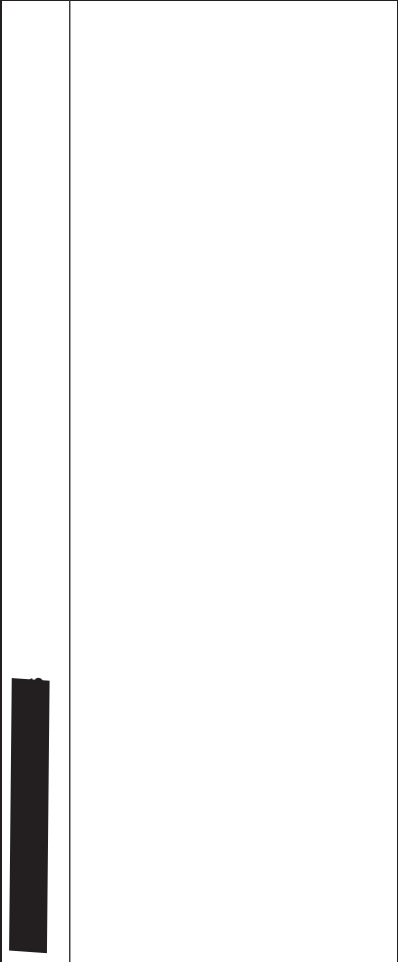



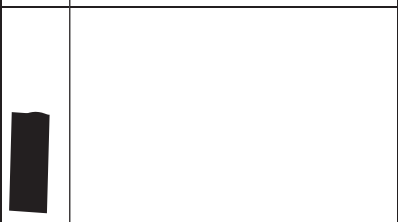
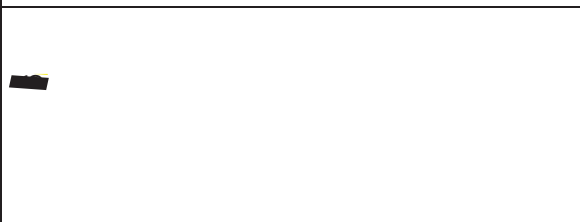
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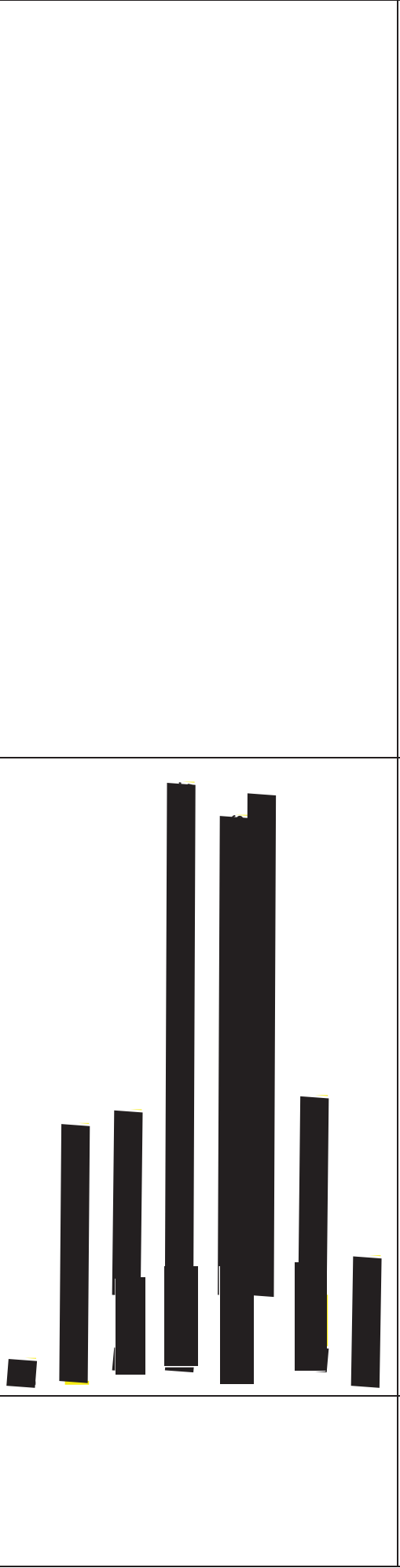
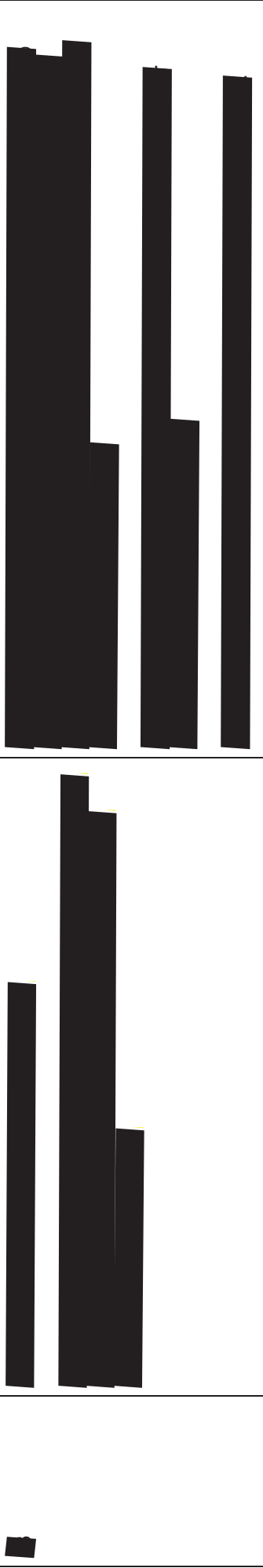



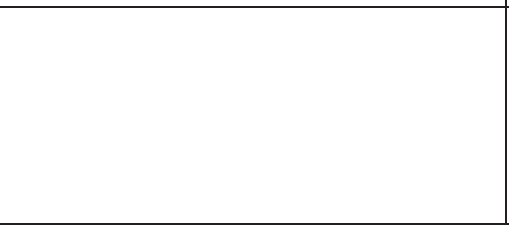
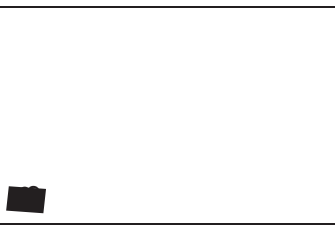








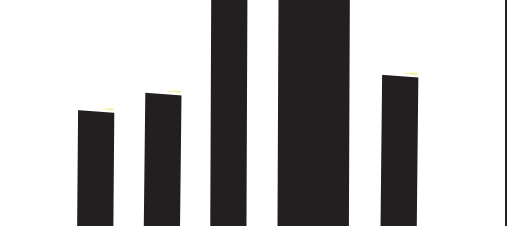
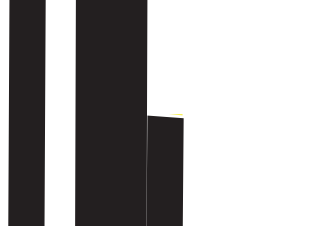



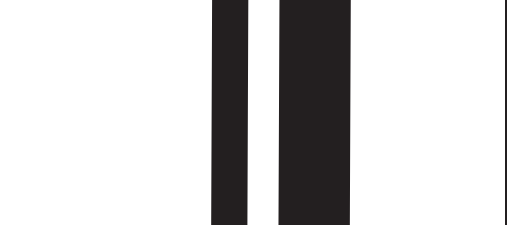




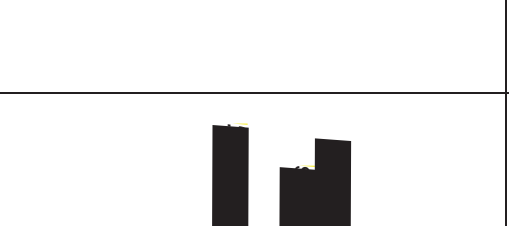





















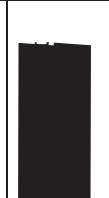
				
				
				

	  	   	       	
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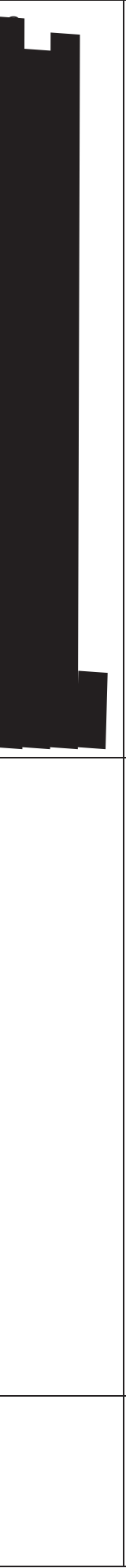
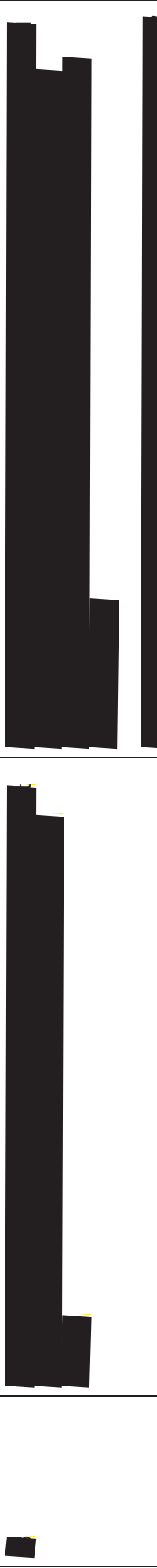
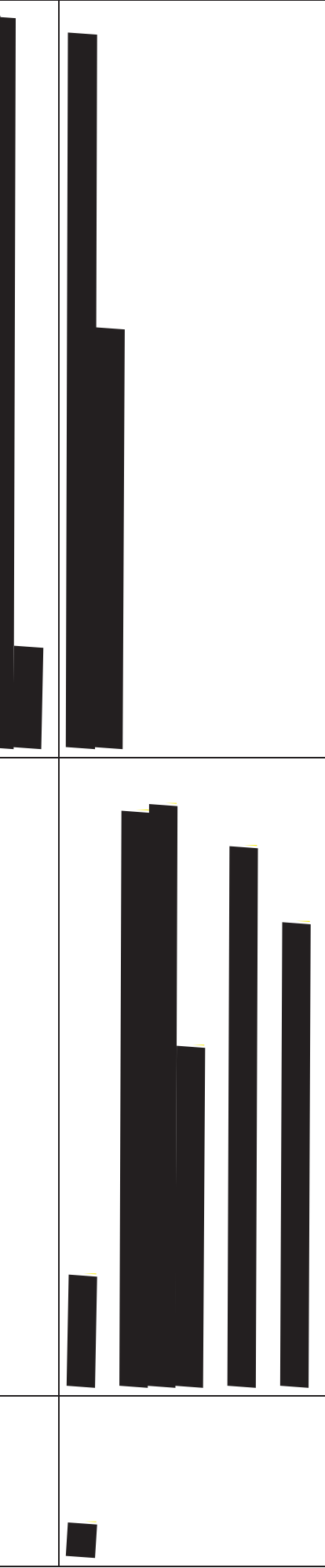


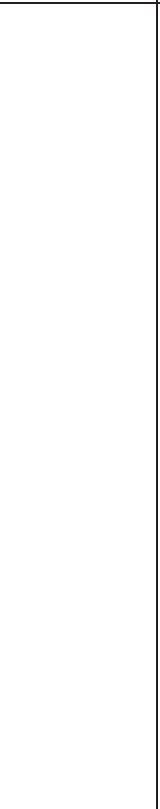

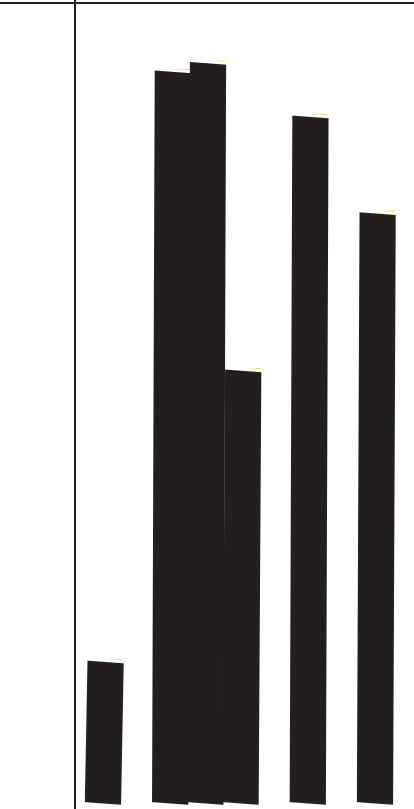


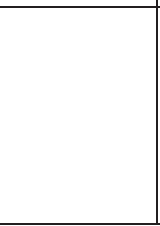


		
		
		

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## **Appendix 6.1 – Step change - Electricity Safety (Electric Line Clearance) Regulations 2010**

In this Appendix, Powercor Australia 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 Powercor Australia'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.

Powercor Australia'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 Powercor Australia to undertake vegetation clearance in accordance with the Regulations, these costs reflect the increased costs Powercor Australia will be required to pay if the 2010 Line Clearance Regulations come into effect. Powercor Australia submits that the AER should accept those step change costs as reasonably reflecting the opex criteria.

In this Revised Regulatory Proposal Powercor Australia has corrected an error in only setting out the step change costs of complying with the requirements of the 2005 Line Clearance Regulations and Code in respect of LBRA. Powercor Australia omitted in its Initial Regulatory Proposal to identify the step change costs associated with complying with the 2005 Line Clearance Regulations and Code without the exemption in respect of HBRA. Now that the 2010 Line Clearance Regulations are in force, it is clear that this exemption is not reflected in those Regulations. Accordingly, this will result in increased compliance costs for Powercor Australia.

## **Powercor Australia's response to AER's Draft Determination**

In its response to the AER's Draft Determination, below Powercor Australia:

- 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<sup>1</sup>;
- 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.

Powercor Australia 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 Powercor Australia'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.<sup>2</sup> Compliance with the 2010 Line Clearance Regulations will result in increased costs to Powercor Australia which are not reflected in Powercor Australia'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

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<sup>1</sup> Meeting with the AER, ESV and Victorian DNSPs on 13 July 2010.

<sup>2</sup> 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.

changes by performing its own assessment of the changes.<sup>3</sup> In *Application by Energy Australia* [2009]<sup>4</sup> 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.

Powercor Australia has obtained legal advice on the regulatory changes between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations.<sup>5</sup> That legal advice identifies additional key changes to those identified and considered in the Line Clearance RIS.

In this Appendix to its Revised Regulatory Proposal, Powercor Australia

- 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 Powercor Australia in complying with the 2010 Line Clearance Regulations and explains why those cost estimates differ to those previously provided by Powercor Australia to the AER.

#### **Line Clearance RIS failed to correctly identify key changes**

As noted above, Powercor Australia'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;

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<sup>3</sup> 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.*'

<sup>4</sup> ACompT 8 (Attachment 97 to this Revised Regulatory Proposal), at [190]

<sup>5</sup> Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).



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- 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:<sup>6</sup>

- 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;
- 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 Powercor Australia 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

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<sup>6</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p xviii, p60.

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, Powercor Australia 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.<sup>7</sup> The ESV did not make any of the changes to the 2010 Line Clearance Regulations recommended by Powercor Australia,<sup>8</sup> 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 Powercor Australia 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.

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<sup>7</sup> Powercor Australia's Response to the ESV's Line Clearance RIS, 20 May 2010 (Attachment 242 to this Revised Regulatory Proposal).

<sup>8</sup> Powercor Australia, Response to the ESV's Line Clearance RIS, 20 May 2010 (Attachment 242 to this Revised Regulatory Proposal).

*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
- 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**:<sup>9</sup>

- 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 Powercor Australia.

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*'.<sup>10</sup> 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

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<sup>9</sup> Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

<sup>10</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p9.

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distribution business.<sup>11</sup> 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 Powercor Australia from the change between the 2005 Line Clearance Regulations and the 2010 Line Clearance Regulations are \$22,453,360 ((\$9,328-\$4.5m) x5 years)<sup>12</sup>

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.

Powercor Australia 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,<sup>13</sup> Powercor Australia's understanding of the meaning of consult in clause 5(5) is that it requires:

1. Powercor Australia 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, Powercor Australia 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, Powercor Australia is required to genuinely consider the objection. However, Powercor Australia is not required to attempt to reach agreement with the owner or occupier on the removal/cutting. Further, provided Powercor Australia considers the objection, it is not necessary for Powercor Australia 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 Powercor which did not solely relate to notification. The Line Clearance RIS purported to use a cost estimate provided to it by Powercor Australia of \$4.5 million.<sup>14</sup> However, the cost estimate that Powercor Australia provided to ESV was \$5.5 million.

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<sup>11</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p9, 140.

<sup>12</sup> The Line Clearance RIS estimates the cost of notification under the 2010 Line Clearance Regulations to be \$9,328 for Powercor and under the 2005 Line Clearance Regulations to be \$4.5m (p137 and p140 of the Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal). Therefore, according to the RIS, the cost impact of the change from the 2005 Line Clearance Regulations to the 2010 Line Clearance Regulations is a saving of \$122,453,360 for Powercor Australia over 5 years Line Clearance RIS, p137, p140.

<sup>13</sup> Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

<sup>14</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p137.

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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 Powercor Australia's vegetation management systems and processes link the inspection process with the notification and consultation process. ESV was informed of the different components of Powercor Australia's cost estimate in December 2009. A breakdown of those costs is provided in the following table:

Activity	Cost
Notification, consultation and negotiation	\$300,000
Management, IT & data management	\$1.2 million
Inspection, workload identification, contractor management and data capture	\$3.6 million
Auditing	\$400,000
<b>Total</b>	<b>\$5.5 million</b>

Table A6.1.1 Breakdown of costs provided by Powercor Australia to ESV

In its Draft Determination, the AER calculated Powercor Australia's step change cost of complying with the notification requirements of the 2010 Line Clearance Code as \$4,491,000.<sup>15</sup> 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. \$4.5 million) and the cost of complying with the notification requirements in the 2010 Line Clearance Code set out in the Line Clearance RIS (i.e. \$9,000).

As set out above, the component of the cost estimate of complying with the 2005 Line Clearance Code relevant to notification and consultation for Powercor Australia is in fact \$300,000. 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 \$9,000.

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

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<sup>15</sup> AER, Draft Determination, Appendix L, p163.



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 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 Powercor Australia, the Line Clearance RIS sets out a cost increase from the omission of clauses 9.2.1 and 9.2.2 of \$4,833,779 over 5 years.<sup>16</sup> 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 Powercor Australia 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 AusNet. However, in SP AusNet's response to the Line Clearance RIS dated 10 May 2010, consistent with Powercor Australia'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:<sup>17</sup>

*'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.'*

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<sup>16</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p146.

<sup>17</sup> Letter from SP Ausnet 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).



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*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 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 Powercor Australia 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 Powercor Australia in Victoria would be classified as 'native'. Should Powercor Australia 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.<sup>18</sup> 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.<sup>19</sup> 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 Powercor Australia 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

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<sup>18</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p 126.

<sup>19</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p125.

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) Powercor Australia will be required to increase the frequency of pruning across its entire vegetation management program. This is due to Powercor Australia's inability to clear lower growing native vegetation from under powerlines in early stages of growth because these trees are outside the minimum clearance space. Powercor Australia 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 Powercor Australia'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 Powercor Australia'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 Powercor Australia asserts that the AER can be satisfied that Powercor Australia's step change costs reasonably reflect the opex criteria.

#### **Powercor Australia's step change costs**

The following section of this Appendix describes Powercor Australia's proposed step change costs for complying with the 2010 Line Clearance Regulations.

The costs were obtained from Powercor Australia's vegetation clearance contractor, VEMCO.<sup>20</sup> Powercor Australia 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.<sup>21</sup> Powercor Australia provided the legal advice to VEMCO and asked VEMCO to advise it of the cost impact of those changes.<sup>22</sup> VEMCO provided a letter dated 13 July 2010 to Powercor Australia in respect of the cost increases above 2009 actual costs that will apply over the years from January 2011 to December 2015.<sup>23</sup> Since VEMCO is engaged by Powercor Australia to undertake vegetation clearance in accordance with the 2010 Line Clearance Regulations, these costs reflect the increased costs

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<sup>20</sup> Letter from VEMCO to CitiPower and Powercor Australia dated 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal). Note that Powercor Australia has not proposed a step change for items 5 and 9 of VEMCO's letter.

<sup>21</sup> Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

<sup>22</sup> Note that VEMCO's estimates of the cost of complying with the 2010 Line Clearance Regulations have changed slightly from those provided by Powercor Australia 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.

<sup>23</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

Powercor Australia will be required to pay now that the 2010 Line Clearance Regulations have come into effect.

Powercor Australia notes that these costs differ from the cost estimates provided by Powercor Australia to the AER on 4 March 2010. Since that time, as noted above Powercor Australia 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, Powercor Australia asked its service provider VEMCO to calculate the cost impact of those changes, having regard to that legal advice.<sup>24</sup> As a result, Powercor Australia's understanding of the cost implications of the 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 Powercor Australia are:

- the removal of the exemption;
- 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;
- the requirement in Table 2 of the 2010 Line Clearance Code for larger clearance spaces for spans exceeding 100 metres than Table 10.1 of the 2005 Line Clearance Code;
- changes to the notification and consultation requirements;
- the new restrictions on the cutting and removal of native trees and trees of cultural or environmental significance; and
- the new requirement for habitat trees to be cut or removed outside breeding season wherever practicable.

#### *Removal of exemption*

The 2010 Line Clearance Regulations do not replicate the exemption granted to Powercor Australia and other Victorian distributors from compliance with requirements of the 2005 Line Clearance Code in LBRA and HBRA. The exemption requirements in respect of LBRA were referred to in Powercor Australia's Initial Regulatory Proposal.<sup>25</sup>

In its Initial Regulatory Proposal, Powercor Australia incorrectly classified its proposed step change for LBRA costs in respect of the 2005 Line Clearance

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<sup>24</sup> Letter of advice from DLA Phillips Fox to Powercor Australia and CitiPower dated 21 June 2010 (Attachment 244 to this Revised Regulatory Proposal).

<sup>25</sup> Initial Regulatory Proposal, p172.

Regulations as costs of achieving compliance with the Regulations without the exemption. As explained later in this Appendix, those costs were costs for achieving compliance with the 2005 Line Clearance Regulations with the exemption.

However, in its Initial Regulatory Proposal Powercor Australia omitted to provide information on the step change costs associated with complying with the requirements of the 2010 Line Clearance Regulations without the exemption in respect of HBRA.

The exemption granted by the ESV on 21 December 2005 also exempted Powercor Australia from the 2005 Line Clearance Code's clearance requirements in HBRA.<sup>26</sup> The exemption in respect of HBRA provides:

*'Powercor is exempted from the requirement to maintain a clearance space in accordance with clause 2.1 of the Code of Practice for Electric Line Clearance (the Code) provided that Powercor achieves the minimum clearance space requirements specified in Tables 9.3 and 11.1 of the Code during:*

- (a) the fire danger period, in an area declared under section 4 of the Country Fire Authority act 1958 (CFA Act) for an area; or*
- (b) for the period 15 December to 31 March for an area in which there is no fire danger period declared under section 4 of the CFA Act.'*

The ESV confirmed in December 2009 that it will not issue a new exemption when the current exemption expires and that the exemption would not form part of the 2010 Line Clearance Regulations.<sup>27</sup>

In HBRA Powercor Australia is currently compliant with the clearance space requirements required by the 2005 Line Clearance Code with the exemption. Since this exemption does not apply after 29 June 2010, however, Powercor Australia will incur increased costs in complying with the 2010 Line Clearance Code as a result of the removal of the exemption that are not reflected in Powercor Australia's 2009 base year opex. VEMCO has advised Powercor Australia that the following cost increases above 2009 actual costs will apply over the years from January 2011 to December 2015 as a result of the removal of the exemption in HBRA.<sup>28</sup>

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<sup>26</sup> Initial Regulatory Proposal, document RP-P0068.

<sup>27</sup> Letter from Paul Fearon ESV to Garry Audley Powercor, 7 December 2009 (Attachment 246 to this Revised Regulatory Proposal).

<sup>28</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

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	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (HBRA)</b>	8,200	7,300	5,600	4,400	3,300	<b>28,800</b>

**Table A6.1.2 HBRA step change costs**

These costs reflect the additional work which Powercor Australia will be required to undertake to comply with the 2010 Line Clearance Code given the removal of the exemption.

The AER states in its Draft Determination that it sought advice from ESV as to whether its understanding that the expiration of the exemptions will not require the DNSPs to increase the frequency of their pruning cycles, or undertake mid cycle inspections and pruning was correct and the ESV confirmed it was correct.<sup>29</sup> As explained below, the ESV is incorrect in its assessment.

The removal of the exemption requires a significant shift in the cyclic inspection and clearing cycles in HBRA. The current HBRA exemption only requires compliance with the minimum clearance space requirements during a fire danger period or during 15 December to 31 March for an area in which there is no fire danger period declared. Accordingly, the current Powercor Australia strategy is not designed to maintain clearances outside of those periods.

To comply with the 2010 Line Clearance Code without this exemption Powercor Australia will have to:

- respond more quickly to rectification codes 55 and 56 during the non-declared fire season; and
- bring forward annual clearing programs to establish a minimum 12 month re-growth buffer to the minimum clearance space.

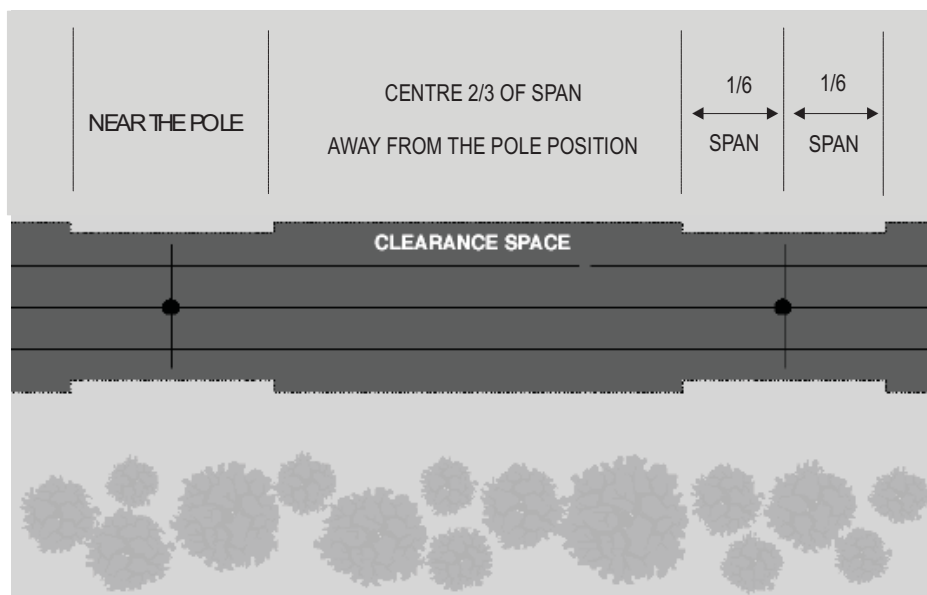
Response to rectification codes

Each pole in Powercor Australia's distribution network is assigned a vegetation clearance code for when it is anticipated that the vegetation surrounding the pole and adjacent span will enter the required clearance space under the 2010 Line Clearance Regulations. The codes are assigned by VEMCO during inspections or clearance of vegetation. The codes are checked by Powercor Australia.

A span is the section of the powerline between two poles. The following diagram from the 2010 Line Clearance Code shows a span and how the clearance space operates.

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<sup>29</sup> AER, Draft Determination, p170.



**Figure A6.1.1 Clearance space**

The majority of spans are coded with year codes e.g. 12 would indicate the span had vegetation that is expected to require attention in 2012. The vegetation clearance codes also include two codes for instances where vegetation is within the minimum clearance space, these codes are required for those instances where the growth conditions have resulted in greater than anticipated growth: code 55 - vegetation touching conductor, and code 56 - vegetation inside clearance space.

Generally, Powercor Australia maintains the clearance spaces with a pruning cycle of 3 years in rural areas and 2 years in urban areas. When pruning is undertaken the vegetation is cut to seek to ensure that the clearance space is maintained for 3 years in rural areas and 2 years in urban areas, allowing for regrowth of vegetation during that time and sag and sway of the powerlines. While VEMCO seeks to undertake all pruning and clearing to achieve the appropriate clearance space until the next pruning cycle, sometimes as a result of unexpected regrowth conditions vegetation enters the clearance space in between pruning cycles. The rectification periods for code 55 and 56 vegetation are in response to vegetation that has entered the minimum clearance space as a result of unexpected regrowth conditions.

In practice, in HBRA during the declared fire season, Powercor Australia responds to code 55 (touching the line) within 24 hours and code 56 (vegetation in the clearance space) within 48 hours. Outside of the declared fire season, Powercor Australia responds to code 55 and code 56 within six months and prior to the next fire danger period or earlier if risk assessments require it due to public safety, immediate powerline safety (hazard trees) or potential reliability impacts.

The removal of the exemption will necessitate a faster response time to codes 55 and 56 during the non-declared fire season. Similar response times will be required to instances of code 55 and 56 outside of the declared fire season. Powercor Australia proposes to respond to code 55 (touching the line) within 24



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hours and code 56 (vegetation in the clearance space) within 18 weeks outside of the declared fire season.

Accordingly, the cost estimates set out in Table A6.1.2 above are based on achieving the following rectification times from 2013.

	Code 55 rectification time	Code 56 rectification time
During declared fire danger period	24 hours	48 hours
Outside declared fire danger period	24 hours	18 weeks

Table A6.1.3 Rectification times

Should the ESV require more stringent rectification times, Powercor Australia's operating costs will increase.

Bringing forward of annual clearing program

The removal of the exemption means that the volume of spans for which vegetation is required to be cut will increase and there will be a need to cut the vegetation surrounding those spans further to ensure that it does not grow into the clearance space at any time between cutting cycles. As a result, the annual clearing program will have to be brought forward.

The following diagram shows the impact of the removal of the exemption. Trees that are cut assuming a three year cycle will be in a non-compliant state after 3 years of growth and will now have to be cut for another year's growth or cut earlier and so more frequently (i.e. after their second year of growth).

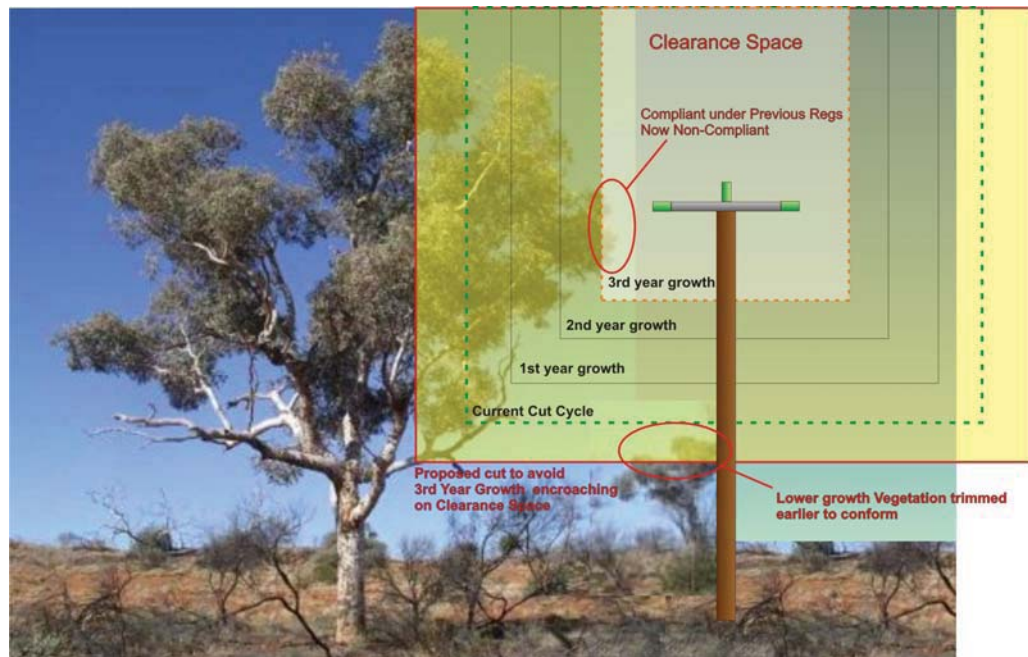


Figure A6.1.2 Impact of removal of exemption

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This will require VEMCO to employ more people and obtain more equipment to undertake the work. Powercor Australia is anticipating a 3 year compliance transition period to achieve compliance with the Code in HBRA (without any exemption). However, once compliance is achieved, there will still be increased costs as a result of the need to create a wider buffer around the spans than would apply with the exemption to ensure the vegetation does not grow into the clearance space at any time between cutting cycles. Accordingly, after 2012 there will still be costs associated with the step change, however, those costs reduce each year from 2013-15.

The consequences of the removal of the exemption for Powercor Australia's cutting program are set out in the table below:

<b>Year</b>	<b>Activities 'with exemption'</b>	<b>Activities 'without exemption'</b>
2011	Prior to the 2011/12 summer the spans relating to all poles classified codes 55, 56 and 11 would be inspected and the vegetation surrounding those spans will be either cut or reclassified	<p>Poles classified code 12 will need to be brought into the cutting cycle.</p> <p>Prior to the 2010/11 summer the spans relating to all poles classified codes 55, 56, 11 and 12 will need to be inspected and the vegetation surrounding those spans will be either cut to ensure that it does not grow into the clearance space at any time between cutting cycles or reclassified</p>
2012	Prior to the 2012/13 summer the spans relating to all poles classified codes 55, 56 and 12 would be inspected and the vegetation surrounding those spans will be either cut or reclassified	<p>Poles classified code 13 will need to be brought into the cutting cycle.</p> <p>Prior to the 2011/12 summer the spans relating to all poles classified codes 55, 56, 12 and 13 will need to be inspected and the vegetation surrounding those spans will be either cut to ensure that it does not grow into the clearance space at any time between cutting cycles or reclassified.</p>
2013	Prior to the 2013/14 summer the spans relating to all poles classified codes 55, 56 and 13 would be inspected and the vegetation surrounding those spans will be either cut or reclassified	<p>Poles classified code 14 will need to be brought into the cutting cycle.</p> <p>Prior to the 2011/12 summer the spans relating to all poles classified codes 55, 56, 13 and 14 will need to be inspected and the vegetation surrounding those spans will be either cut to ensure that it does not grow into the clearance space at any time between cutting cycles or reclassified.</p>
2014	Prior to the 2014/15 summer the spans relating to all poles classified codes 55, 56 and 14 would be inspected and the vegetation surrounding those spans will be either cut or reclassified	<p>Poles classified code 15 will need to be brought into the cutting cycle.</p> <p>Prior to the 2011/12 summer the spans relating to all poles classified codes 55, 56, 14 and 15 will need to be inspected and the vegetation surrounding those spans will be either cut to ensure that it does not grow into the clearance space at any time between cutting cycles or</p>

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		reclassified.
2015	Prior to the 2015/16 summer the spans relating to all poles classified codes 55, 56 and 15 would be inspected and the vegetation surrounding those spans will be either cut or reclassified	<p>Poles classified code 16 will need to be brought into the cutting cycle.</p> <p>Prior to the 2011/12 summer the spans relating to all poles classified codes 55, 56, 15 and 16 will need to be inspected and the vegetation surrounding those spans will be either cut to ensure that it does not grow into the clearance space at any time between cutting cycles or reclassified.</p>

**Table A6.1.4 Cutting program consequences of removal of exemption**

*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. Powercor Australia 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

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overhead service cables and failed to take into account the cost implications with respect to all aerial and insulated cables.<sup>30</sup>

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.

Powercor Australia 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, Powercor Australia can achieve compliance with the omission of the exception in clause 9.3.

VEMCO advised Powercor Australia 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.<sup>31</sup>

	\$'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	2,896	2,896	2,896	2,896	2,896	14,481
Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – service lines from pole to building	4,199	4,199	4,199	4,199	4,199	20,996

**Table A6.1.5 Omission of exceptions in clauses 9.2.1, 9.2.2 and 9.3 step change costs**

*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

<sup>30</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p146.

<sup>31</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

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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.

Powercor Australia 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 Powercor Australia 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.<sup>32</sup>

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (omission of clauses 10(b) and (c) and Tables 10.2 and 10.3)</b>	2,475	2,475	1,485	1,485	1,485	<b>9,405</b>

**Table A6.1.6 Omission of clauses 10(b) and (c) and Tables 10.2 and 10.3 step change costs**

*Larger clearance space for LBRA*

There is a larger clearance space requirement for spans exceeding 100 metres in Table 2 of the 2010 Line Clearance Code, than that required by Table 10.1 of the 2005 Line Clearance Code.

Table 2 of the 2010 Line Clearance Code provides that the minimum clearance space for spans exceeding 100 metres is:

- 2.5 metres for powerlines up to 1kV;
- 2.5 metres for powerlines over 1kV and less than 66kV; and
- metres for 66kV powerlines.

In contrast, according to Table 10.1 of the 2005 Line Clearance Code, the minimum clearance space for spans exceeding 100 metres is:

- 1.5 metres for bare and covered low voltage powerlines;
- 2 metres for 6.6kV, 11kV and 22kV powerlines; and

<sup>32</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).



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- 3 metres for 66kV powerlines.

In addition, under the 2005 Line Clearance Code and under the 2010 Line Clearance Code (for spans exceeding 100 metres) to achieve the required clearance space an additional distance must be added to the minimum clearance space to allow for the sag and sway of the cables and for vegetation regrowth during the period between cutting times (clause 11(3) and notes 2 and 3 of the Notes under Table 2 of the 2010 Line Clearance Code and the note under Table 10.1 of the 2005 Line Clearance Code).

Accordingly, Table 2 of the 2010 Line Clearance Code requires a larger clearance space for spans exceeding 100 metres than Table 10.1 of the 2005 Line Clearance Code. That is, the required clearance space for spans exceeding 100 metres has been increased by 1 metre for powerlines under 1kV and 0.5 metres for powerlines over 1kV. The clearance space requirements for spans exceeding 100 metres in Table 2 of the 2010 Line Clearance Code for LBRA are larger than the clearance space requirements for spans exceeding 100 metres in Table 3 of the 2010 Line Clearance Code for HBRA.

The larger clearance space requirements will result in a significant increase in expenditure. Powercor Australia has a large number of LBRA spans that exceed 100 meters. 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 this change to the LBRA clearance space requirements.

VEMCO has advised Powercor Australia that it will face increased costs as a result of this change to clearance space requirements.<sup>33</sup> It has informed Powercor Australia that the following cost increases above 2009 actual costs will apply over the years from January 2011 to December 2015 as a result of this change to clearance space requirements in LBRA.<sup>34</sup>

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (larger clearance spaces in LBRA)</b>	1,460	1,460	1,460	1,460	1,460	<b>7,300</b>

**Table A6.1.7 Requirement for larger clearance spaces in LBRA 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.

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<sup>33</sup> Note that this change was clarified following further review of the 2010 Line Clearance Code after Powercor Australia submitted its Response to the Line Clearance RIS. Accordingly, it was not included in Powercor Australia's response to the RIS.

<sup>34</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).



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VEMCO has reviewed DLA Phillips Fox's legal advice dated 21 June 2010<sup>35</sup> 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.<sup>36</sup>

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 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 VEMCO's 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 Powercor Australia 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.<sup>37</sup>

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (notification and consultation)</b>	(2)	(2)	(2)	(2)	(2)	(8)

**Table A6.1.8 Notification and consultation step change costs**

<sup>35</sup> Attachment 244 to this Revised Regulatory Proposal.

<sup>36</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

<sup>37</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

*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 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 Powercor Australia in Victoria would be classified as 'native'. Should Powercor Australia 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.<sup>38</sup>

VEMCO advised Powercor Australia 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.<sup>39</sup>

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (clause 2(3))</b>	0	764	1,019	2,038	2,547	<b>6,368</b>

**Table A6.1.9 Protection of native trees step change costs**

*Habitat trees*

Clause 4 provides that cutting or removal of trees that are the habitat of vulnerable, endangered or critically endangered species under the *Flora and Fauna Guarantee Act 1988* is to be undertaken outside of breeding season wherever practicable and if not practicable translocation of fauna must be undertaken.

The Line Clearance RIS failed to assess the costs of complying with clause 4.

Compliance with clause 4 will require the employment of an additional qualified full time employee to adequately identify habitat trees prior to cutting or removing trees.

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<sup>38</sup> ESV, Line Clearance RIS (Attachment 241 to this Revised Regulatory Proposal), p125.

<sup>39</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

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VEMCO advised Powercor Australia that the following cost increases above 2009 actual costs will apply over the years from January 2011 to December 2015 to comply with clause 4 of the 2010 Line Clearance Code.<sup>40</sup>

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (habitat trees)</b>	100	100	100	100	100	<b>500</b>

Table A6.1.10 Protection of habitat trees step change costs

### **LBRA Compliance**

In its Initial Regulatory Proposal in determining the costs associated with complying with the requirements of the Regulations and the Code in LBRA, Powercor Australia assumed that the Regulations and the Code that would apply from 1 July 2010 would be the same as or similar to the 2005 Line Clearance Regulations and Code.<sup>41</sup> As noted in its Initial Regulatory Proposal, Powercor Australia has an exemption from ESV for compliance with certain clearance space requirements in the Code in LBRA.<sup>42</sup> The ESV has indicated that it will not issue a new exemption when that exemption expires on 30 June 2010.

In its Initial Regulatory Proposal, the step change cost for LBRA was mischaracterised as a cost of complying with the 2005 Line Clearance Code in LBRA without the exemption from the Code requirements granted by the ESV in December 2005. However, the step change cost proposed was actually for the costs of achieving compliance with the 2005 Line Clearance Regulations in LBRA with the exemption.

Nuttall Consulting commented on the step change costs proposed by Powercor Australia by noting that Powercor Australia *'has not identified any benefits associated with the proposed opex step change'*.<sup>43</sup> Since this step change is proposed in order to achieve compliance with the 2010 Line Clearance Regulations and the 2010 Line Clearance Code it is not necessary to demonstrate the benefits of the expenditure in order to establish that the expenditure is prudent and efficient. Rather, the appropriate assessment is whether the expenditure is necessary to achieve compliance with the 2010 Line Clearance Regulations and the 2010 Line Clearance Code.

#### *Background to LBRA costs*

<sup>40</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

<sup>41</sup> Initial Regulatory Proposal, p173.

<sup>42</sup> Initial Regulatory Proposal, p173. Energy Safe Victoria, Exemptions granted to Powercor Australia under reg. 10 of the Electricity Safety (Electric Line Clearance Regulations) 2005 (Attachment 249 to this Revised Regulatory Proposal).

<sup>43</sup> Nuttall Consulting, Report – Capital Expenditure, 4 June 2010, p329.

A chronology setting out Powercor Australia'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 Regulations and 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 Regulations as to the clearance between electric lines and vegetation during the Proclaimed Fire Declaration Period. Accordingly, in the ESCV's 2006-10 EDPR, ESCV 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.

In November 2005, Powercor Australia 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 Powercor Australia from compliance with the 2005 Line Clearance Code. The appeals resumed in January 2006 at which time 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.

The ESCV Appeal Panel determined that Powercor Australia's desire to move from practical compliance to literal compliance with the 2005 Line Clearance Regulations for LBRA did not constitute a step change.<sup>44</sup> The ESCV Appeal Panel 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:<sup>45</sup>

*'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.<sup>46</sup> It is clear from the chronology that ESV did in fact change its enforcement activities during the 2006-10 regulatory control

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<sup>44</sup> ESCV, ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal), paragraphs 27 and 28.

<sup>45</sup> ESCV, ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal), paragraphs 27.

<sup>46</sup> ESCV, ESCV Appeal Panel Decision (Attachment 243 to this Revised Regulatory Proposal), paragraph 30.

period to require literal compliance with the 2005 Line Clearance Regulations and exemption.

The chronology shows that from 2006 to 2008 Powercor Australia 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 Powercor Australia as necessary to quantify the extent of non-compliance. In September 2008 Powercor Australia 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.<sup>47</sup> By letter dated 7 May 2009 ESV informed Powercor Australia that it was not in a position to approve the Vegetation Management 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.

As set out in the Initial Regulatory Proposal<sup>48</sup>, on 12 June 2009 Powercor Australia informed 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.<sup>49</sup> Accordingly, Powercor Australia was not given an allowance in respect of those costs in the ESCV's 2006-10 EDPR.

As noted in Powercor Australia's Initial Regulatory Proposal<sup>50</sup>, 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 Powercor Australia's base year opex. However, there will still be additional costs in 2011, 2012 and 2013 associated with achieving full compliance above those reflected in Powercor Australia'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.

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<sup>47</sup> Initial Regulatory Proposal p173.

<sup>48</sup> Initial Regulatory Proposal, p173.

<sup>49</sup> ESCV 2006-10 EDPR (Attachment 31 to this Revised Regulatory Proposal), pp223-24.

<sup>50</sup> Initial Regulatory Proposal, p174.

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The following table shows the difference between Powercor Australia's compliance policy in 2005 and the compliance policy which it has sought to implement since 2005:

Pre 2006	Post 2006
<p>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.</p> <p>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.</p> <p>Those compliance targets were:</p> <ul style="list-style-type: none"> <li>• Spans assigned code 55: <ul style="list-style-type: none"> <li>○ surrounding 66kV powerlines lines actioned within 24 hours;</li> <li>○ surrounding 22kV powerlines actioned within 28 days;</li> <li>○ surrounding low voltage powerlines actioned within 6 months.</li> </ul> </li> <li>• Spans assigned code 56: <ul style="list-style-type: none"> <li>○ surrounding 66kV powerlines lines actioned within 4 months;</li> <li>○ surrounding 22kV and low voltage powerlines actioned within 12 months.</li> </ul> </li> </ul>	<p>Inspection is undertaken for vegetation surrounding high voltage powerlines every 2 years and for vegetation surrounding low voltage powerlines every 3 years.</p> <p>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.</p>

**Table A6.1.11 Changes to compliance with clearance spaces in LBRA**

It is highly likely that 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 Powercor Australia's costs of achieving full compliance with the Line Clearance Regulations and Line Clearance Code during that period.

In the Initial Regulatory Proposal, Powercor Australia identified the following step change costs of complying with the 2005 Line Clearance Regulations and 2005 Line Clearance Code in respect of LBRA:<sup>51</sup>

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (LBRA)</b>	2,134	1,972	881	(33)	3,352	8,307

**Table A6.1.12 LBRA step change cost in Initial Regulatory Proposal**

<sup>51</sup> Initial Regulatory Proposal, p174.



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In calculating these costs Powercor Australia made an error. VEMCO has advised Powercor Australia that the following costs above 2009 actual costs will apply during the period January 2011 to the end of December 2015 in respect of Powercor Australia's program of achieving compliance with the clearance space requirements in LBRA.<sup>52</sup>

	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (LBRA)</b>	2,187	2,038	(83)	(892)	0	<b>3,250</b>

**Table A6.1.13 LBRA step change costs in Revised Regulatory Proposal**

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 Powercor Australia'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 Powercor Australia's base year opex to determine the step change set out above.

In addition to the costs of achieving compliance with the clearance space requirements in the 2005 Line Clearance Regulations and Code in LBRA, in order to be compliant with the 2010 Line Clearance Code in LBRA Powercor Australia 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 and the requirement in Table 2 of the 2010 Line Clearance Code for larger clearance space for spans exceeding 100 meters. 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.

### **Powercor Australia's Revised Regulatory Proposal**

Powercor Australia 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.

<sup>52</sup> Letter from VEMCO to CitiPower and Powercor Australia, 13 July 2010 (Attachment 245 to this Revised Regulatory Proposal).

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	\$'000 (\$2010)					
	2011	2012	2013	2014	2015	Total
<b>Vegetation Clearance (HBRA)</b>	8,200	7,300	5,600	4,400	3,300	<b>28,800</b>
<b>Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – lines from pole to pole</b>	2,896	2,896	2,896	2,896	2,896	<b>14,481</b>
<b>Vegetation Clearance (omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3) – service lines from pole to building</b>	4,199	4,199	4,199	4,199	4,199	<b>20,996</b>
<b>Vegetation Clearance (omission of clauses 10(b) and (c) and Tables 10.2 and 10.3)</b>	2,475	2,475	1,485	1,485	1,485	<b>9,405</b>
<b>Vegetation Clearance (larger LBRA clearance spaces)</b>	1,460	1,460	1,460	1,460	1,460	<b>7,300</b>
<b>Vegetation Clearance (notification and consultation)</b>	(2)	(2)	(2)	(2)	(2)	<b>(8)</b>
<b>Vegetation Clearance (clause 2(3) native trees)</b>	0	764	1,019	2,038	2,547	<b>6,368</b>
<b>Vegetation Clearance (habitat trees)</b>	100	100	100	100	100	<b>500</b>
<b>Vegetation Clearance (LBRA)</b>	2,187	2,038	(83)	(892)	0	<b>3,250</b>
<b>Total Vegetation Clearance Step Change</b>	<b>21,516</b>	<b>21,231</b>	<b>16,675</b>	<b>15,685</b>	<b>15,986</b>	<b>91,093</b>

Table 6.14 Step changes – Electricity Safety (Electric Line Clearance) Regulations

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**CHRONOLOGY OF VEGETATION MANGEMENT COMPLIANCE**

The following is a joint chronology for Powercor Australia and CitiPower.

Date	Event	Description
15/07/05	Letter from Ken Gardner, Chief Electrical Inspector Office of Chief Electrical inspector to Garry Audley CitiPower Pty <sup>53</sup>	<p>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.</p> <p>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.</p>
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 <sup>54</sup>	<p>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:</p> <p style="text-align: center;"><i>'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.'</i></p>
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	<p>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:</p> <ul style="list-style-type: none"> <li>• 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 danger</li> </ul>

<sup>53</sup> Attachment 248 to this Revised Regulatory Proposal.

<sup>54</sup> Attachment 248 to this Revised Regulatory Proposal.

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Date	Event	Description
		<p>period or the period 15 December to 31 March where there is no declared fire danger period.</p> <ul style="list-style-type: none"> <li>• 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.</li> <li>• 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.</li> </ul>
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 <sup>55</sup>	<p>ESCV Appeal Panel:</p> <ul style="list-style-type: none"> <li>• 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.</li> <li>• 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.</li> <li>• 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</li> </ul>

<sup>55</sup> Attachment 243 to this Revised Regulatory Proposal.

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Date	Event	Description
		<p>to treat CitiPower/Powercor Australia's present compliance regime as adequate.</p> <ul style="list-style-type: none"> <li>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.</li> </ul>
12/10/06	ESCV's 2006-10 EDPR (amended in accordance with ESCV Appeal Panel's decision) (published on 19/10/06) <sup>56</sup>	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 <sup>57</sup>	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 <sup>58</sup>	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	ESV acknowledged receipt of Vegetation Management Plans for CitiPower and Powercor Australia.

<sup>56</sup> Attachment 31 to this Revised Regulatory Proposal.

<sup>57</sup> Letter from CitiPower/Powercor Australia to ESV dated 4 August 2009 (Attachment 248 to this Revised Regulatory Proposal), at 1.1.4.

<sup>58</sup> 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.

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Date	Event	Description
	Networks CitiPower/Powercor Australia <sup>59</sup>	
7/05/09	Letters from Ken Gardner Director of Energy Safety, ESV to Garry Audley General Manager Electricity Networks CitiPower/Powercor Australia <sup>60</sup>	<p>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.</p> <p>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.</p> <p>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.</p>
13/05/09	Email from Garry Audley to Ken Gardner, ESV <sup>61</sup>	<p>Refers to letters from ESV of 7/05/09.</p> <p>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.</p> <p>Notes that CitiPower/Powercor Australia remain fully compliant for HBRA [with the exemptions] and the staged component only relates to LBRA.</p> <p>Requests meeting with Ken Gardner.</p>
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 <sup>62</sup>	<p>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.</p> <p>Powercor Australia was surprised by ESV's recent letters indicating non-approval of its Vegetation Management Plan.</p> <p>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.</p> <p>States that if ESV supports this approach CitiPower/Powercor Australia will resubmit both Vegetation Management Plans on this basis.</p>
30/07/09	Letter from Ken Gardner, Director of Energy Safety	Refers to letter of 12/06/09 from CitiPower/Powercor Australia.

<sup>59</sup> Attachment 248 to this Revised Regulatory Proposal.

<sup>60</sup> Attachment 248 to this Revised Regulatory Proposal.

<sup>61</sup> Attachment 248 to this Revised Regulatory Proposal.

<sup>62</sup> Attachment 248 to this Revised Regulatory Proposal.



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Date	Event	Description
	ESV to John Misfund Acting General Manager Electricity Networks CitiPower/Powercor Australia <sup>63</sup>	Requests a detailed explanation as to why CitiPower/Powercor Australia are not 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 <sup>64</sup>	<p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p>
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 <sup>65</sup> ESV confirmed that it would not re-create the exemptions following the remaking of the 2005 Line Clearance Regulations.	<p>Paul Fearon Director ESV confirmed the intention of ESV to remake the 2005 Line Clearance Regulations prior to the sunset of those Regulations.</p> <p>Also confirmed the exemptions would cease to have any effect when those Regulations sunset.</p> <p>Confirmed that ESV did not intend to re-create the exemptions following the remaking of the 2005 Line Clearance Regulations.</p>
10/09	CitiPower/Powercor Australia provided its revised 2009/10 management plan to ESV	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.
28/10/09	Letter from Paul Fearon,	Responds to Powercor Australia's letter of 4/08/09. ESV is supportive of the efforts

<sup>63</sup> Attachment 248 to this Revised Regulatory Proposal.

<sup>64</sup> Attachment 248 to this Revised Regulatory Proposal.

<sup>65</sup> Letter from Paul Fearon, Director ESV to Garry Audley General Manager Electricity Networks Powercor Australia dated 7 December 2009 (Attachment 246 to this Revised Regulatory Proposal).

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Date	Event	Description
	Acting Director of Energy Safety ESV to Garry Audley, General Manager Electricity Networks Powercor Australia <sup>66</sup>	<p>Powercor Australia has taken to address the long standing 2005 Line Clearance Code non-compliance issues in its LBRA.</p> <p>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.</p> <p>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 the 2005 Line Clearance Code non-compliance in the LBRA where Powercor Australia is the responsible person.</p>
7/12/09	Letter from Paul Fearon, Director General Energy Safety to Garry Audley, Powercor Australia <sup>67</sup>	ESV confirmed that it did not intend to re-create the exemptions created in December 2005 and early 2006 after the sunseting of the 2005 Line Clearance Regulations.
25/02/09	ESV published Line Clearance RIS <sup>68</sup>	<p>Proposed 2010 Line Clearance Regulations do not contain in any form the exemptions granted in respect of the 2005 Line Clearance Regulations.</p> <p>Public comments due on the proposed Regulations by 25/05/09.</p>
20/05/10	Letter from Garry Audley, General Manager Electricity Networks CitiPower/Powercor Australia to Paul Fearon, Acting Director General of Energy Safety ESV <sup>69</sup>	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.

<sup>66</sup> Attachment 248 to this Revised Regulatory Proposal.

<sup>67</sup> Attachment 246 to this Revised Regulatory Proposal.

<sup>68</sup> Attachment 241 to this Revised Regulatory Proposal.

<sup>69</sup> Attachment 242 to this Revised Regulatory Proposal.

## Appendix 16.1 - Close out of the S Factor Scheme

In this Appendix, Powercor Australia 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
<b>Total reward</b>				<b>0</b>	<b>-10</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>10</b>

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 'Powercor - 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.

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	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	
<b>Total reward</b>				<b>0</b>	<b>-10</b>	<b>-10</b>	<b>-10</b>	<b>-10</b>	<b>-10</b>	<b>-10</b>	<b>0</b>

**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.

### **Powercor Australia's Initial Regulatory Proposal and Revised Regulatory Proposal**

Powercor Australia'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 Powercor Australia's Initial Regulatory Proposal on this matter.

Powercor Australia 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 Powercor Australia's proposed ESCV scheme true up calculation and the AER's STPIS would operate together on the equivalent assumed performance in the prior examples.

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	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
<b>Total reward</b>				<b>0</b>	<b>-10</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>10</b>

**Table A16.1.3 Example of operation of Powercor Australia's proposed approach**

Powercor Australia'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 - Powercor Australia's Proposed Charges for Alternative Control Services**

In this Appendix Powercor Australia 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, Powercor Australia proposes the following charges for fee based alternative control services.

<b>Powercor Alternative Control Services - Fee Based Services</b>	<b>2011 Charges (\$2010)</b>
Meter Accuracy Test - single phase (BH)	342.45
Meter Accuracy Test - single phase (AH)	373.22
Meter Accuracy Test - Single phase additional meter (BH)	139.94
Meter Accuracy Test - multi phase (BH)	438.83
Meter Accuracy Test - multi phase (AH)	479.20
Meter Accuracy Test - Multi phase additional meter (BH)	236.72
Meter Accuracy Test - CT (BH)	430.14
Meter Accuracy Test - CT (AH)	469.64
Meter Investigation Test (BH)	271.34
Meter Investigation Test (AH)	295.03
Reconnections (incl Customer Transfer) BH	18.71
Reconnections (same day) BH	29.58
Reconnections (incl Customer Transfer) AH	77.67
Disconnection (BH only)	19.80
Disconnection (no AH service)	-
Disconnection for non payment (BH only)	19.80
Special reading BH	15.70
Special reading AH - no service	-
Service Truck Visit BH	454.52
Service Truck Visit AH	447.90
Wasted Truck Visit BH	238.12
Wasted Truck Visit AH	259.93
Reserve Feeder - Subtransmission - \$ per KVA	0.78



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<b>Powercor Alternative Control Services - Fee Based Services</b>	<b>2011 Charges (\$2010)</b>
Reserve Feeder - High Voltage - \$ per KVA	3.99
Reserve Feeder - Low Voltage - \$ per KVA	14.46
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh BH	337.65
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh AH	370.08
New Connections Responsible for metering	
Single phase BH	364.08
Single phase AH	388.87
Multi phase DC BH	469.46
Multi phase DC AH	494.25
Multi phase CT BH	1,950.30
Multi phase CT AH	2,104.35
New Connections Not Responsible for metering	
Single phase BH	306.43
Single phase AH	331.22
Multi phase DC BH	411.81
Multi phase DC AH	436.59
Multi phase CT BH	1,892.65
Multi phase CT AH	2,046.70
Solar PV Conn - Single phase BH (unit cost)	204.76
Solar PV Conn - Single phase AH (unit cost)	217.79

**Table A19.1.1 Powercor Australia's proposed charges for fee based alternative control services**

## Labour rates for quoted alternative control services

In this Revised Regulatory Proposal, Powercor Australia proposes the following labour rates for quoted alternative control services.

<b>Powercor Alternate Control Service - Proposed Quoted Services</b>	<b>2011 \$'s Per hour per Person (Real \$2010 ex GST)</b>
General Line Worker - Business Hours	112.11
General Line Worker - After Hours	123.28
Design/Survey - Business Hours	120.31
Design/Survey - After Hours	135.50
Administration	45.34

Table A19.1.2 Powercor Australia's proposed labour rates for quoted alternative control services

## Prices for public lighting

In this Revised Regulatory Proposal, Powercor Australia proposes the following prices for public lighting.

<b>Public Lighting Prices</b>	<b>2011 Charges Real \$2010 (ex GST)</b>
Mercury vapour 80 watt	42.74
Sodium high pressure 150 watt	75.26
Sodium high pressure 250 watt	77.17
Flourescent 20 watt	118.81
Flourescent 40 watt	118.81
Mercury vapour 50 watt	59.40
Mercury vapour 125 watt	57.69
Mercury vapour 250 watt	58.65
Mercury vapour 400 watt	67.91
Mercury vapour 700 watt	102.63
Sodium low pressure 90 watt	101.60
Sodium low pressure 180 watt	101.60
Sodium high pressure 400 watt	102.63
Incandescent 100 watt	118.81
Incandescent 150 watt	118.81
Metal halide 250 watt	102.63
Metal halide 400 watt	102.63
T5 2X14W	33.49

Table A19.1.3 Powercor Australia's proposed prices for public lighting