AUSTRALIAN COMPETITION TRIBUNAL

Application by United Energy Distribution Pty Limited [2012] ACompT 1

Citation:	Application by United Energy Distribution Pty Limited [2012] ACompT 1
Review from:	Australian Energy Regulator
Parties:	**UNITED ENERGY DISTRIBUTION PTY LIMITED (ABN 70 064 651 029)** **SPI ELECTRICITY PTY LIMITED (ABN 91 064 235 776)** **CITIPOWER PTY (ABN 76 064 651 056)** **POWERCOR AUSTRALIA LIMITED (ABN 89 064 651 109)** **JEMENA ELECTRICITY NETWORKS (VIC) LTD (ACN 064 651 083)**
File numbers:	ACT 6 of 2010 ACT 7 of 2010 ACT 8 of 2010 ACT 9 of 2010 ACT 10 of 2010
Tribunal:	**FOSTER J (DEPUTY PRESIDENT),** **MR G LATTA AM AND PROFESSOR D ROUND**
Date of decision:	6 January 2012
Legislation:	*Acts Interpretation Act 1901* (Cth) *Competition and Consumer Act 2010* (Cth), s 44AAF *Corporations Act 2001* (Cth) *Electricity Safety (Bushfire Mitigation) Amendment Interim Regulations 2010* *Electricity Safety Act 1998 (Vic) s 113A of Div 2A of Pt 10* *Electricity Safety (Electric Line Clearance) Regulations 2005, cll 9, 9.1, 9.3, 12, reg 10* *Electricity Safety (Electric Line Clearance) Regulations 2010, Table 2* *Interpretation of Legislation Act 1984* (Vic), s 27, s 28(2) *National Electricity Law*, ss 2, 2B, 2C, 2D, 3, 5, 7, 7A, 8, 9, 11(2), 14B, 15, 16, 16(1)(b), 18, 28D, 28ZC, 57B, 71B,

	71C, 71C(1), 71C(1)(c), 71C(1)(d), 71C(2), 71J(b), 71L, 71M, 71N, 71O, 71O(2), 71P, s 71P(2)(a), 71R, 71R(3), 71R(3)(b), 71R(4), 71R(5), 71R(6), Part 4 Div 1, Part 6 Div 3A, Part 3 Div 6, Part 7, Schedule 1, Schedule 2 cll 1, 1(2), 2, 7, 8, 11, 12, 13, 15, 17, 19, 23–26, 31–34, 39, 42 and 43 *National Electricity (South Australia) Act 1996*, ss 11, 12 and 15 *National Electricity (Victoria) Act 2005*, ss 3, 16(4)(b), s 23 *National Electricity (Victoria) Amendment Act 2007*, s 5 *National Gas Law*, s 245 *Electricity Safety (Electric Line Clearance) Regulations 2005*, cl 9 *National Electricity (Economic Regulation of Distribution Services) Amendment Rules 2007* *National Electricity Rules (Version 39)* Chapter 6, Ch 10 Glossary, Pt C and Pt E of Ch 6, Sch 6.1 and Sch 6.2 to Ch 6, cll 1.7.1, 6.2.5(b)(4), 6.3.1(a), 6.3.1(b), 6.3.1(c)(1), 6.3.1(c)(2), 6.4.1, 6.4.2, 6.4.2(a), 6.4.2(b)(1), 6.4.2(3), 6.4.2(4), 6.4.3, 6.4.3(a), 6.4.3(a)(1), 6.4.3(a)(2), 6.4.3(a)(5), 6.4.3(a)(6), 6.4.3(a)(7), 6.4.3(b)(1)(i), 6.4.3(b)(2), 6.4.3(b)(5), 6.4.3(b)(6), 6.4.3(b)(7), 6.5.1, 6.5.1(a), 6.5.1(e), 6.5.1(e)(3), 6.5.1(f), 6.5.2, 6.5.2(a), 6.5.2(b), 6.5.2(c), 6.5.2(d), 6.5.2(e) ,6.5.3(b)(2), 6.5.6, 6.5.6(a), 6.5.6(b), 6.5.6(c), 6.5.6(d), 6.5.6(e), 6.5.7(a), 6.5.7(b), 6.5.7(c), 6.5.7(d), 6.5.7(e), 6.5.8, 6.6.1(a), 6.6.1(c), 6.6.1(d), 6.6.1(e), 6.6.1(i), 6.6.1(j), 6.6.2, 6.6.2(a), 6.6.3, 6.12, 6.12.1, 6.12.1(2), (3) and (4), 6.12.1(4)(ii), 6.12.1(5), 6.12.1(6), 6.12.1(11), 6.12.1(12), 6.12.1(13), 6.12.1(14), 6.12.1(18), 6.12.2, 6.12.3, 6.12.3(a), 6.12.3(f), 6.14, 6A.7.3, S6.1.2, S6.2.1, S6.2.1(a)(1), S6.2.1(a)(2), S6.2.1(b), S6.2.1(c), S6.2.1(c)(1), S6.2.1(c)(2), S6.2.1(c)(3), S6.2.1(d), S6.2.1(e), S6.2.1(e)(1), S6.2.1(f), S6.2.2, S6.2.3, S6A.2.1(f)(1), 9.29.5(b)(2) Victorian Public Lighting Code, cl 2.1(c)
Cases cited:	*Application by ActewAGL Distribution* (2010) ATPR 42-324 *Application by Energex Limited (Gamma) (No 5)* (2011) ATPR 42-356 *Application by EnergyAustralia and Ors* (2009) ATPR 42-299 *Application by Epic Energy South Australia Pty Ltd* (2003) ATPR 41-932 *Application by Jemena Gas Networks (NSW) Ltd (No 5)* (2011) ATPR 42-360 *Australian Competition and Consumer Commission v Australian Comepetition Tribunal* (2006) 152 FCR 33

Dates of hearing:	20, 21, 22, 23 and 27 June 2011; 4, 5, 6, 7, 12, 22 and 25 July 2011
Date of last submissions:	21 December 2011
Place:	Sydney
Category:	No Catchwords
Number of paragraphs:	671
Counsel for United Energy Distribution Pty Limited:	Mr AC Archibald QC and SR Horgan SC; Mr C Furnell (Streetlight issues only)
Solicitor for United Energy Distribution Pty Limited:	Johnson Winter & Slattery
Counsel for SPI Electricity Pty Limited:	Mr D Farrands and Mr A Weinstock Mr C Furnell (Streetlight issues only)
Solicitor for SPI Electricity Pty Limited:	SP AusNet
Counsel for Citipower Pty and Powercor Australia Limited:	Mr M Connock SC and Mr M Rush Mr C Furnell (Streetlight issues only)
Solicitor for Citipower Pty and Powercor Australia Limited:	DLA Phillips Fox
Counsel for Jemena Electricity Networks (Vic) Ltd:	Mr AJ Myers QC and Mr MI Borsky Mr C Furnell (Streetlight issues only)
Solicitor for Jemena Electricity Networks (Vic) Ltd:	Gilbert + Tobin
Counsel for the Australian Energy Regulator:	Ms M Sloss SC, Mr S Lloyd SC, Mr P Gray, Mr D Star, Dr V Priskich, Mr T Clarke and Mr L Merrick
Solicitor for the Australian Energy Regulator:	Corrs Chambers Westgarth
Counsel for the Minister for Energy and Resources for the State of Victoria (Intervener):	Mr P Hanks QC and Mr G McCormick
Solicitor for the Minister for Energy and Resources for the State of Victoria (Intervener):	Minter Ellison

Counsel for Streetlight Group of Councils (Interveners):	Mr G Nash QC
Solicitor for Streetlight Group of Councils (Interveners):	McKean Park

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 6 of 2010

RE:	**APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO UNITED ENERGY DISTRIBUTION PTY LIMITED PURSUANT TO CLAUSE 6.11.1 OF CHAPTER 6 OF THE NATIONAL ELECTRICITY RULES**
BY:	**UNITED ENERGY DISTRIBUTION PTY LIMITED (ABN 70 064 651 029)**
TRIBUNAL:	**JUSTICE FOSTER (DEPUTY PRESIDENT), MR G LATTA AM AND PROFESSOR D ROUND**
DATE OF ORDER:	**6 JANUARY 2012**
WHERE MADE:	**SYDNEY**

THE TRIBUNAL:

1. Pursuant to s 71P(2)(a) of the *National Electricity Law*, hereby varies the Final Distribution Determination dated October 2010 in respect of the 2011–2015 regulatory control period applicable to the applicant (United Energy Distribution Pty Limited) (**the final determination**) by:

   (a) Replacing the figure “3.74%” for the debt risk premium in Table 13 of the final determination with the figure “3.89%”; and

   (b) Replacing the figure “0.5” as the value for gamma with the figure “0.25” as the value for gamma when used as an input into the calculation of the cost of corporate income tax.

2. Grants liberty to apply to the applicant and to the Australian Energy Regulator in respect of the consequences of the Tribunal’s decision in respect of the indexation of the regulatory asset base of Jemena Electricity Networks (Vic) Ltd made this day (6 January 2012) in proceeding No ACT 10 of 2010, *Application by Jemena Electricity Networks (Vic) Ltd (ACN 064 651 083)*.

3. Pursuant to s 71P(2)(b) of the *National Electricity Law*, remits the final determination to the Australian Energy Regulator to be remade upon a basis which does not involve the application of the methodology for closing out the ESCV “S” Factor Scheme

devised by the Australian Energy Regulator and applied by it in arriving at the final determination but which, subject to the variations made in par 1 above and to the grant of any additional relief resulting from the exercise of the liberty to apply in par 2 above, otherwise proceeds upon the basis of the final determination as published by the Australian Energy Regulator in October 2010.

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 7 of 2010

RE:	**APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO SPI ELECTRICITY PTY LIMITED PURSUANT TO CLAUSE 6.11.1 OF THE NATIONAL ELECTRICITY RULES**
BY:	**SPI ELECTRICITY PTY LIMITED (ABN 91 064 235 776)**
TRIBUNAL:	**JUSTICE FOSTER (DEPUTY PRESIDENT), MR G LATTA AM AND PROFESSOR D ROUND**
DATE OF ORDER:	**6 JANUARY 2012**
WHERE MADE:	**SYDNEY**

THE TRIBUNAL:

1. Pursuant to s 71P(2)(a) of the *National Electricity Law*, hereby varies the Final Distribution Determination dated October 2010 in respect of the 2011–2015 regulatory control period applicable to the applicant (SPI Electricity Pty Limited) (**the final determination**) by:

    (a) Replacing the figure “4.05%” for the debt risk premium in Table 14 of the final determination with the figure “4.22%”; and

    (b) Replacing the figure “0.5” as the value for gamma with the figure “0.25” as the value for gamma when used as an input into the calculation of the cost of corporate income tax.

2. Grants liberty to apply to the applicant and to the Australian Energy Regulator in respect of the consequences of the following decisions made by the Tribunal this day (6 January 2012):

    (a) The decision in respect of the closeout of the ESCV “S” Factor Scheme made in proceeding No ACT 6 of 2010, A*pplication by United Energy Distribution Pty Ltd (ABN 70 064 651 029*); and

(b) The decision in respect of the indexation of the regulatory asset base of Jemena Electricity Networks (Vic) Ltd in proceeding No ACT 10 of 2010, *Application by Jemena Electricity Networks (Vic) Ltd (ACN 064 651 083)*.

3. Subject to the variations made in par 1 above, subject to the remitter in par 2 of the relief granted by the Tribunal in *Application by SPI Electricity Pty Limited* [2012] ACompT 2 and to the grant of any additional relief resulting from the exercise of liberty to apply in par 2 above, pursuant to s 71P(2)(a) of the *National Electricity Law*, otherwise affirms the final determination.

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 8 of 2010

RE:	**APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO CITIPOWER PTY PURSUANT TO CLAUSE 6.11.1 OF THE NATIONAL ELECTRICITY RULES**
BY:	**CITIPOWER PTY (ABN 76 064 651 056)**
TRIBUNAL:	**JUSTICE FOSTER (DEPUTY PRESIDENT),** **MR G LATTA AM AND PROFESSOR D ROUND**
DATE OF ORDER:	**6 JANUARY 2012**
WHERE MADE:	**SYDNEY**

THE TRIBUNAL:

1. Pursuant to s 71P(2)(a) of the *National Electricity Law*, hereby varies the Final Distribution Determination dated October 2010 in respect of the 2011–2015 regulatory control period applicable to the applicant (CitiPower Pty) (**the final determination**) by:

   (a) Replacing the figure “3.74%” for the debt risk premium in Table 14 of the final determination with the figure “3.89%”; and

   (b) Replacing the figure “0.5” as the value for gamma with the figure “0.25” as the value for gamma when used as an input into the calculation of the cost of corporate income tax.

2. Grants liberty to apply to the applicant and to the Australian Energy Regulator in respect of the consequences of the following decisions made by the Tribunal this day (6 January 2012):

   (a) The decision in respect of the closeout of the ESCV “S” Factor Scheme made in proceeding No ACT 6 of 2010, *Application by United Energy Distribution Pty Ltd (ABN 70 064 651 029)*; and

(b) The decision in respect of the indexation of the regulatory asset base of Jemena Electricity Networks (Vic) Ltd in proceeding No ACT 10 of 2010, *Application by Jemena Electricity Networks (Vic) Ltd (ACN 064 651 083*).

3. Pursuant to s 71P(2)(b) of the *National Electricity Law*, remits the final determination to the Australian Energy Regulator to be remade in light of a reconsideration by the Australian Energy Regulator of the applicant's claims in accordance with the *National Electricity Rules* in respect of the vegetation management opex step change claimed by the applicant, such reconsideration to, subject to the variations made in par 1 above and to the grant of any additional relief resulting from the exercise of the liberty to apply in par 2 above, otherwise proceed upon the basis of the final determination as published by the Australian Energy Regulator in October 2010.

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 9 of 2010

RE:	**APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO POWERCOR AUSTRALIA LIMITED PURSUANT TO CLAUSE 6.11.1 OF THE NATIONAL ELECTRICITY RULES**
BY:	**POWERCOR AUSTRALIA LIMITED (ABN 89 064 651 109)**
TRIBUNAL:	**JUSTICE FOSTER (DEPUTY PRESIDENT), MR G LATTA AM AND PROFESSOR D ROUND**
DATE OF ORDER:	**6 JANUARY 2012**
WHERE MADE:	**SYDNEY**

THE TRIBUNAL:

1. Pursuant to s 71P(2)(a) of the *National Electricity Law*, hereby varies the Final Distribution Determination dated October 2010 in respect of the 2011–2015 regulatory control period applicable to the applicant (Powercor Australia Limited) (**the final determination**):

   (a) By replacing the figure "3.74%" for the debt risk premium in Table 14 of the final determination with the figure "3.89%";

   (b) By replacing the figure "0.5" as the value for gamma with the figure "0.25" as the value for gamma when used as an input into the calculation of the cost of corporate income tax;

   (c) By replacing the annual revenue requirements for 2011–2015 set out in Table 6 of the final determination with annual revenue requirements for 2011–2015 that have been recalculated by excluding therefrom the 2001–2005 negative carryover arising under the Office of the Regulator-General (Vic)'s 2001–2005 efficiency carryover mechanism applied in respect of the applicant and also by excluding therefrom the 2006–2010 efficiency carryover amount under the Essential Services Commission of Victoria's 2006–2010 electricity efficiency carryover mechanism applied in respect of the applicant; and

(d) Also otherwise as required in order to give effect to the variations made in subpars (a) to (c) above.

2. Grants liberty to apply to the applicant and to the Australian Energy Regulator in respect of the consequences of the following decisions made by the Tribunal this day (6 January 2012):

(a) The decision in respect of the closeout of the ESCV "S" Factor Scheme made in proceeding No ACT 6 of 2010, *Application by United Energy Distribution Pty Ltd (ABN 70 064 651 029)*; and

(b) The decision in respect of the indexation of the regulatory asset base of Jemena Electricity Networks (Vic) Ltd in proceeding No ACT 10 of 2010, *Application by Jemena Electricity Networks (Vic) Ltd (ACN 064 651 083)*.

3. Pursuant to s 71P(2)(b) of the *National Electricity Law*, remits the final determination to the Australian Energy Regulator to be remade in light of a reconsideration by the Australian Energy Regulator of the applicant's claims in accordance with the *National Electricity Rules* in respect of the vegetation management opex step change claimed by the applicant, such reconsideration to, subject to the variations made in par 1 above and to the grant of any additional relief resulting from the exercise of the liberty to apply in par 2 above, otherwise proceed upon the basis of the final determination as published by the Australian Energy Regulator in October 2010.

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 10 of 2010

RE:	**APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO JEMENA ELECTRICITY NETWORKS (VIC) LTD PURSUANT TO CLAUSE 6.11.1 OF CHAPTER 6 OF THE NATIONAL ELECTRICITY RULES**
BY:	**JEMENA ELECTRICITY NETWORKS (VIC) LTD (ACN 064 651 083)**
TRIBUNAL:	**JUSTICE FOSTER (DEPUTY PRESIDENT), MR G LATTA AM AND PROFESSOR D ROUND**
DATE OF ORDER:	**6 JANUARY 2012**
WHERE MADE:	**SYDNEY**

THE TRIBUNAL:

1. Pursuant to s 71P(2)(a) of the *National Electricity Law*, hereby varies the Final Distribution Determination dated October 2010 in respect of the 2011–2015 regulatory control period applicable to the applicant (Jemena Electricity Networks (Vic) Ltd) (**the final determination**) by:

   (a) Replacing the figure “3.70%” for the debt risk premium in Table 14 of the final determination with the figure “4.34%”; and

   (b) Replacing the figure “0.5” as the value for gamma with the figure “0.25” as the value for gamma when used as an input into the calculation of the cost of corporate income tax;

   (c) Including in the forecast capital allowance for the applicant for the 2011–2015 regulatory control period an allowance in the amount confidentially agreed between the Australian Energy Regulator and the applicant in respect of the Broadmeadows project, such amount being recorded in confidential Joint Submissions made to the Tribunal in writing by the solicitors for the Australian Energy Regulator and the solicitors for the applicant and dated 11 July 2011; and

(d) Allowing the amounts claimed by the applicant in its revised regulatory proposal in the enterprise support function cost centres described as:

(i) Energy Investment;

(ii) Financial Strategy; and

(iii) Investment Analysis

as allowances in the forecast operating expenditure of the applicant.

2. Grants liberty to apply to the applicant and to the Australian Energy Regulator in respect of the consequences of the decision made by the Tribunal this day (6 January 2012) in respect of the closeout of the ESCV "S" Factor Scheme made in proceeding No ACT 6 of 2010, *Application by United Energy Distribution Pty Ltd (ABN 70 064 651 029*).

3. Pursuant to s 71P(2)(b) of the *National Electricity Law*, remits the final determination to the Australian Energy Regulator to be remade upon a basis which conforms to the requirements of the *National Electricity Rules* in respect of the indexation of the regulatory asset base of the applicant for inflation in accordance with these Reasons for Decision but which, subject to the variations made in par 1 above and to the grant of any additional relief resulting from the exercise of the liberty to apply in par 3 above, otherwise proceeds uupon the final determination as published by the Australian Energy Regulator in October 2010.

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 6 OF 2010

RE: **APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO UNITED ENERGY DISTRIBUTION PTY LIMITED PURSUANT TO CLAUSE 6.11.1 OF CHAPTER 6 OF THE NATIONAL ELECTRICITY RULES**

BY: **UNITED ENERGY DISTRIBUTION PTY LIMITED (ABN 70 064 651 029)**

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 7 OF 2010

RE: **APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO SPI ELECTRICITY PTY LIMITED PURSUANT TO CLAUSE 6.11.1 OF THE NATIONAL ELECTRICITY RULES**

BY: **SPI ELECTRICITY PTY LIMITED (ABN 91 064 235 776)**

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 8 OF 2010

RE: **APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO CITIPOWER PTY PURSUANT TO CLAUSE 6.11.1 OF THE NATIONAL ELECTRICITY RULES**

BY: **CITIPOWER PTY (ABN 76 064 651 056)**

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 9 OF 2010

RE: **APPLICATION UNDER SECTION 71B OF THE NATIONAL**

	ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO POWERCOR AUSTRALIA LIMITED PURSUANT TO CLAUSE 6.11.1 OF THE NATIONAL ELECTRICITY RULES
BY:	**POWERCOR AUSTRALIA LIMITED (ABN 89 064 651 109)**

IN THE AUSTRALIAN COMPETITION TRIBUNAL

NO: ACT 10 OF 2010

RE:	**APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO JEMENA ELECTRICITY NETWORKS (VIC) LTD PURSUANT TO CLAUSE 6.11.1 OF CHAPTER 6 OF THE NATIONAL ELECTRICITY RULES**
BY:	**JEMENA ELECTRICITY NETWORKS (VIC) LTD (ACN 064 651 083)**
TRIBUNAL:	**FOSTER J (DEPUTY PRESIDENT), MR G LATTA AM AND PROFESSOR D ROUND**
DATE:	**6 JANUARY 2012**
PLACE:	**SYDNEY**

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REASONS FOR DECISION

INTRODUCTION

1 On 29 October 2010, the Australian Energy Regulator (**AER**) published its final determination and its reasons for that determination (**the final decision**) as to the basis upon which electricity distribution services in the State of Victoria will be provided by the registered distribution network service providers in that State (**DNSPs**) for the period 2011–2015. The final decision was made under the *National Electricity Law* (**NEL**) and the *National Electricity Rules (Version 39)* (**NER**). At the same time, the AER made five separate distribution determinations (one for each of the DNSPs) by which it gave effect to the final decision.

2 The final decision constituted the first electricity determination made by the AER on the price control regime to apply to the DNSPs. The previous determination (ie that which applied for the regulatory period 2006–2010) had been made by the Essential Services Commission of Victoria (**ESCV**).

3 The final decision and the individual distribution determinations took effect on 1 January 2011.

4 The final decision provided for combined increases in forecast opex and capex for the DNSPs in respect of the regulatory control period 2011–2015 of $4.7 billion for capex and $2.7 billion for opex over expenditure in the same categories for the 2006–2010 period.

5 There are five registered DNSPs in Victoria. These are:

(i) CitiPower Pty (**CitiPower**);

(ii) Powercor Australia Limited (**Powercor**);

(iii) Jemena Electricity Networks (Vic) Ltd (**JEN**);

(iv) SPI Electricity Pty Limited (**SP AusNet**); and

(v) United Energy Distribution Pty Limited (**UED**).

6 Each of those DNSPs has the exclusive right for the relevant regulatory period to provide electricity distribution services in a specific (but limited) geographical area.

Attached to these Reasons as Attachment "A" is a map of Victoria showing the particular geographical area allocated to each DNSP.

7 Each of the DNSPs was dissatisfied with aspects of the final decision and consequently with the distribution determination which gave effect to it. Each DNSP has made application to the Tribunal pursuant to s 71B of the NEL for a review of its distribution determination. The Tribunal granted leave to each of them to do so. Each DNSP is entitled to raise the grounds of review specified in its review application. Pursuant to s 71J(b) of the NEL, the Victorian Minister for Energy and Resources (**the Minister)** was joined as an intervener to each of the review applications made by the DNSPs. Pursuant to s 71L of the NEL, the Streetlight Group of Councils (**SGC**) was given a limited right to intervene in the DNSPs review applications in relation to certain public lighting issues.

8 There is no dispute that, in each case, the distribution determination made by the AER is a *reviewable regulatory decision* within the meaning of that expression in s 71B.

9 There are, therefore, five applications before the Tribunal. These are:

(i) ACT 6 of 2010 (Application by UED);

(ii) ACT 7 of 2010 (Application by SP AusNet);

(iii) ACT 8 of 2010 (Application by CitiPower);

(iv) ACT 9 of 2010 (Application by Powercor); and

(v) ACT 10 of 2010 (Application by JEN).

10 UED has also instituted judicial review proceedings in the Federal Court of Australia (VID 989 of 2010).

11 Each review applicant before the Tribunal has raised a number of complaints about the final decision. Some complaints are raised by more than one DNSP. In the case of some complaints, the DNSPs do not have a common position. No one DNSP was a party to every issue raised before the Tribunal.

12 In light of the above circumstances, the Tribunal resolved to deal with the matters before it on an issue by issue basis. In this way, the submissions and arguments of all

interested parties directed to particular issues were heard at the one time. Having approached the hearing in this way, we think that these Reasons should follow the same format.

13 We will, therefore, address the matters before us on an issue by issue basis, broadly in the order in which those issues were addressed at the hearing. Subject to the need to preserve confidentiality in respect of one issue, there will be one set of Reasons for all five review applications. In due course, it will be necessary to make appropriate orders to give effect to these Reasons.

14 Before embarking upon that task, we propose to describe the legislative scheme which now governs the regulation of the DNSPs and the present review applications.

THE LEGISLATIVE SCHEME

15 The legislative scheme governing the National Electricity Market (**NEM**) was established under co-operative arrangements involving the Commonwealth and the States of New South Wales, Victoria, Queensland, South Australia and Tasmania. South Australia is the lead legislature. The relevant South Australian legislation is the *National Electricity (South Australia) Act 1996* (**NESA**). The NEL is set out in the Schedule to the NESA. The NEL provides for the making of National Electricity Regulations (**NERegs**) and NER.

16 Section 11 of the NESA provides as follows:

> **11—General regulation-making power for National Electricity Law**
>
> (1) The Governor may make such regulations as are contemplated by, or necessary or expedient for the purposes of, the National Electricity Law.
>
> (2) Regulations under this Part may—
>
> (a) be of general or limited application;
>
> (b) vary according to the persons, times, places or circumstances to which they are expressed to apply.
>
> (3) Regulations under this Part may be made only on the unanimous recommendation of the Ministers of the participating jurisdictions.
>
> (5) Section 10 of the *Subordinate Legislation Act 1978* does not apply to a regulation under this Part.

17 Section 12 of the NESA describes a number of specific matters that may be covered by the NERegs. One such matter is the transition from the old National Electricity Law to the NEL. Another is the time at which amendments are to take effect.

18 Section 15 of the NESA provides:

15—Conferral of functions and powers on Commonwealth bodies

(1) Clause 2 of Schedule 2 of the National Electricity Law will have effect in relation to the operation of any provision of this Act, or any regulation made under this Act, as if the provision or regulation formed part of the National Electricity Law.

(2) Subsection (1) does not limit the effect that a provision or regulation would validly have apart from the subsection.

19 Clause 2 of Sch 2 to the NEL is a provision which relates to the interpretation of the NEL.

20 Victoria acceded to the co-operative scheme in respect of electricity on 1 January 2009.

21 Prior to 1 January 2009, the regulation of electricity distribution and pricing in Victoria had been undertaken by the Office of the Regulator-General (Vic) (**ORG**) (for the period 2001–2005) and the ESCV (for the period 2006–2010).

22 The ORG issued an Electricity Distribution Price Determination in respect of the regulatory period 2001–2005. That Determination was published in final form in December 2000. The ESCV issued the Electricity Distribution Price Review (2006–2010) in respect of the regulatory period 2006–2010. That Determination was published in final form in December 2008. It had been originally published in October 2005.

23 In late 2007, a Bill was introduced into the Victorian Parliament for the purpose of implementing the Australian Energy Market Agreement (**AEMA**), which is an agreement reached at the Council of Australian Governments (**COAG**). That Agreement had been made in anticipation of amendments to the NEL and the NER which would provide that the AER would regulate all distribution networks in the NEM. The Bill contained transitional provisions in respect of the transfer of responsibility for the economic regulation of electricity distribution from the ESCV to the AER. The Bill provided that the AER would become responsible for the next review in Victoria which was scheduled to commence in January 2009. The Bill also provided that, when the transfer of responsibility from the ESCV to the AER took place, the AER would assume responsibility for the existing price determination

(ie that determination which was in force as at 1 January 2009). That determination was to continue in force until the end of 2010 in accordance with its terms.

24 Effective 1 January 2008, the *National Electricity (Economic Regulation of Distribution Services) Amendment Rules 2007* inserted a new Chapter 6 into the NER. That Chapter of the NER is of critical importance in the matters with which the Tribunal is currently concerned. It is headed: *Economic Regulation of Distribution Services*. We will refer to Ch 6 of the NER in detail, as required, later in these Reasons. The relevant version of the NER for present purposes is Version 39.

25 Section 5 of the *National Electricity (Victoria) Amendment Act 2007* (Act No 66 of 2007), which commenced on 1 January 2009, provided for the transition of economic regulatory functions from the ESCV to the AER.

26 The upshot of these legislative changes was that the responsibility for administering the last price determination put in place by the ESCV (viz that which was in force for the period 2006–2010) was transferred to the AER on 1 January 2009. In addition, the responsibility for the future regulation of the distribution networks of electricity in Victoria passed to the AER (see esp s 23 of the *National Electricity (Victoria) Act 2005* (**NEVA**), which was inserted into that Act by s 5 of Act No 66 of 2007).

27 It will also be necessary to refer to NEVA in more detail later in these Reasons.

28 Section 2 (Definitions) of the NEL contains a number of definitions which are pertinent to the present matters. These definitions, which apply in the NEL, are:

> ***AEMC*** means the Australian Energy Market Commission established by section 5 of the *Australian Energy Market Commission Establishment Act 2004* of South Australia;
>
> ***AER*** means the Australian Energy Regulator established by section 44AE of the *Trade Practices Act 1974* of the Commonwealth;
>
> ***AER economic regulatory decision*** means a decision (however described) of the AER under this Law or the Rules performing or exercising an AER economic regulatory function or power;
>
> ***AER economic regulatory function or power*** means a function or power performed or exercised by the AER under this Law or the Rules that relates to—
>
> (a) the economic regulation of services provided by—

(i) a regulated distribution system operator by means of, or in connection with, a distribution system; or

(ii) a regulated transmission system operator or AEMO by means of, or in connection with, a transmission system; or

(b) the preparation of a network service provider performance report; or

(c) the making of a transmission determination or distribution determination; or

(d) an access determination;

application Act means an Act of a participating jurisdiction that applies, as a law of that jurisdiction, this Law or any part of this Law;

associate in relation to a person has the same meaning it would have under Division 2 of Part 1.2 of the *Corporations Act 2001* of the Commonwealth if sections 13, 16(2) and 17 did not form part of that Act;

changeover date means 1 July 2009 or some other date fixed as the changeover date by Ministerial Gazette notice;

Court means—

(a) where this Law applies as a law of the Commonwealth, the Federal Court;

(b) where this Law applies as a law of a participating jurisdiction that is a State or a Territory, the Supreme Court of that jurisdiction;

distribution determination means a determination of the AER under the Rules that regulates any 1 or more of the following:

(a) the terms and conditions for the provision of electricity network services that are the subject of economic regulation under the Rules including the prices an owner, controller or operator of a distribution system charges or may charge for those services;

(b) the revenue an owner, controller or operator of a distribution system earns or may earn from the provision by that owner, controller or operator of electricity network services that are the subject of economic regulation under the Rules;

distribution reliability standard means a standard imposed by or under the Rules or jurisdictional electricity legislation relating to the reliability or performance of a distribution system;

distribution service standard means a standard relating to the standard of services provided by a regulated distribution system operator by means of, or in connection with, a distribution system imposed—

(a) by or under jurisdictional electricity legislation; or

(b) by the AER in accordance with the Rules;

distribution system means the apparatus, electric lines, equipment, plant and buildings used to convey or control the conveyance of electricity that the Rules specify as, or as forming part of, a distribution system;

distribution system safety duty means a duty or requirement under an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, relating to—

(a) the safe distribution of electricity in that jurisdiction; or

(b) the safe operation of a distribution system in that jurisdiction;

draft Rule determination means a determination of the AEMC under section 99;

electricity network service means a service provided by means of, or in connection with, a transmission system or distribution system;

electricity services means services that are necessary or incidental to the supply of electricity to consumers of electricity, including—

(a) the generation of electricity;

(b) electricity network services;

(c) the sale of electricity;

final Rule determination means a determination of the AEMC under section 102;

jurisdictional electricity legislation means an Act of a participating jurisdiction (other than national electricity legislation), or any instrument made or issued under or for the purposes of that Act, that regulates the generation, transmission, distribution, supply or sale of electricity in that jurisdiction;

jurisdictional regulator means—

…

(b) if this Law is applied as a law of the State of Victoria—

(i) the Essential Services Commission established by section 7(1) of the *Essential Services Commission Act 2001* of Victoria; or

(ii) if the functions or powers of that Essential Services Commission under this Law are transferred to the AER by or under a law of Victoria, the AER;

…

MCE means the Ministerial Council on Energy established on 8 June 2001, being the Council of Ministers with primary carriage of energy matters at national level comprising the Ministers representing the Commonwealth, the States, the Australian Capital Territory and the Northern Territory, acting in accordance with its own procedures;

national electricity legislation means—

(a) the *National Electricity (South Australia) Act 1996* of South Australia and Regulations in force under that Act; and

(b) the *National Electricity (South Australia) Law*; and

(c) an Act of a participating jurisdiction (other than South Australia) that applies, as a law of that jurisdiction, any part of—

(i) the Regulations referred to in paragraph (a); or

(ii) the National Electricity Law set out in the Schedule to the Act referred to in paragraph (a); and

(d) the National Electricity Law set out in the Schedule to the Act referred to in paragraph (a) as applied as a law of a participating jurisdiction (other than South Australia); and

(e) the Regulations referred to in paragraph (a) as applied as a law of a participating jurisdiction (other than South Australia);

national electricity market means—

(a) the wholesale exchange operated and administered by AEMO under this Law and the Rules; and

(b) the national electricity system;

national electricity objective means the objective set out in section 7;

National Electricity Rules or Rules means—

(a) the initial National Electricity Rules; and

(ab) additional Minister initiated Rules; and

(b) Rules made by the AEMC under this Law, including Rules that amend or revoke—

(i) the initial National Electricity Rules or additional Minister initiated Rules; or

(ii) Rules made by it;

network revenue or pricing determination means a distribution determination or a transmission determination;

network service provider means a Registered participant registered for the purposes of section 11(2) that owns, controls or operates a transmission system or distribution system that forms part of the interconnected national electricity system;

participating jurisdiction means a jurisdiction that is a participating jurisdiction within the meaning of section 5;

regulated distribution system operator means an owner, controller or operator of a distribution system—

(a) who is a Registered participant; and

(b) whose revenue from, or prices that are charged for, the provision of electricity network services are regulated under a distribution determination;

regulated network service provider means—

(a) a regulated distribution system operator; or

(b) a regulated transmission system operator;

Regulations means the regulations made under Part 4 of the *National Electricity (South Australia) Act 1996* of South Australia that apply as a law of this jurisdiction;

regulatory obligation or requirement has the meaning given by section 2D;

revenue and pricing principles means the principles set out in section 7A;

Tribunal means the Australian Competition Tribunal referred to in the *Trade Practices Act 1974* of the Commonwealth and includes a member of the Tribunal or a Division of the Tribunal performing functions of the Tribunal;

29 Sections 2B, 2C and 2D of the NEL provide:

2B—Meaning of direct control network service

A direct control network service is an electricity network service—

(a) the Rules specify as a service the price for which, or the revenue to be earned from which, must be regulated under a distribution determination or transmission determination; or

(b) if the Rules do not do so, the AER specifies, in a distribution determination or transmission determination, as a service the price for which, or the revenue to be earned from which, must be regulated under the distribution determination or transmission determination.

2C—Meaning of negotiated network service

A negotiated network service is an electricity network service—

(a) that is not a direct control network service; and

(b) that—

(i) the Rules specify as a negotiated network service; or

(ii) if the Rules do not do so, the AER specifies as a negotiated network service in a distribution determination or transmission determination.

2D—Meaning of regulatory obligation or requirement

(1) A regulatory obligation or requirement is—

(a) in relation to the provision of an electricity network service by a regulated network service provider—

(i) a distribution system safety duty or transmission system safety duty; or

(ii) a distribution reliability standard or transmission reliability standard; or

(iii) a distribution service standard or transmission service standard; or

(b) an obligation or requirement under—

(i) this Law or Rules; or

(ii) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that levies or imposes a tax or other levy that is payable by a regulated network service provider; or

(iii) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that regulates the use of land in a participating jurisdiction by a regulated network service provider; or

(iv) an Act of a participating jurisdiction or any instrument made or issued under or for the purposes of that Act that relates to the protection of the environment; or

(v) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act (other than national electricity legislation or an Act of a participating jurisdiction or an Act or instrument referred to in subparagraphs (ii) to (iv)), that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination or transmission determination.

(2) A regulatory obligation or requirement does not include an obligation or requirement to pay a fine, penalty or compensation—

(a) for a breach of—

(i) a distribution system safety duty or transmission system safety duty; or

(ii) a distribution reliability standard or transmission reliability standard; or

(iii) a distribution service standard or transmission service standard; or

(b) under this Law or the Rules or an Act or an instrument referred to in subsection (1)(b)(ii) to (v).

Note—

See also section 7A(2)(b).

30 Section 3 of the NEL provides:

3—Interpretation generally

Schedule 2 to this Law applies to this Law, the Regulations and the Rules and any other statutory instrument made under this Law.

31 Section 5 of the NEL specifies the means by which a jurisdiction may become a participating jurisdiction. It is common ground amongst all parties to the present review that Victoria is a participating jurisdiction.

32 Sections 7, 7A and 8, which are important provisions for present purposes, are in the following terms:

7—National electricity objective

The objective of this Law 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—

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system.

7A—Revenue and pricing principles

(1) The revenue and pricing principles are the principles set out in subsections (2) to (7).

(2) 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.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—

(a) in any previous—

(i) as the case requires, distribution determination or transmission determination; or

(ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or

(b) in the Rules.

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

8—MCE statements of policy principles

(1) Subject to this section, the MCE may issue a statement of policy principles in relation to any matters that are relevant to the exercise and performance by the AEMC of its functions and powers in—

(a) making a Rule; or

(b) conducting a review under section 45.

(2) Before issuing a statement of policy principles, the MCE must be satisfied that the statement is consistent with the national electricity objective.

(3) As soon as practicable after issuing a statement of policy principles, the MCE must give a copy of the statement to the AEMC.

(4) The AEMC must publish the statement in the South Australian Government Gazette and on its website as soon as practicable after it is given a copy of the statement.

33 The national electricity objective (**NEO**) and the revenue and pricing principles (**RPP**) are matters of significance in the interpretation and application of the NEL and the NER. A number of the definitions extracted at [28] above feed into the descriptions of these two concepts found in s 7 and s 7A.

34 The NER have the force of law in Victoria (s 9 of the NEL).

35 Section 11(2) of the NEL relevantly provides that a person must not engage in the activity of owning, controlling or operating, in Victoria, a distribution system that forms part of the interconnected national electricity system unless the person is a registered participant in relation to that activity or is exempt from the requirement of being so registered. Each of the DNSPs is a registered participant in relation to the distribution of electricity services in Victoria.

36 Section 14B of the NEL provides that a regulated distribution system operator (as defined in s 2) must comply with a distribution determination (as defined in s 2) that applies to the electricity network services (as defined in s 2) provided by that operator.

37 Under the NEL, the AER has the functions and powers set out in s 15 of the NEL. That section provides:

> **15—Functions and powers of AER**
>
> (1) The AER has the following functions and powers—
>
> (a) to monitor compliance by—
>
> (i) Registered participants and other persons with this Law, the Regulations and the Rules; and
>
> (ii) regulated network service providers with network revenue or pricing determinations; and
>
> (iii) AEMO with this Law, the Rules, the Regulations or a transmission determination; and
>
> (b) to investigate breaches or possible breaches of provisions of this Law, the Regulations or the Rules, including offences against this Law; and
>
> (c) to institute and conduct proceedings—
>
> (i) against relevant participants under section 61 of this Law or section 44AAG of the *Trade Practices Act 1974* of the Commonwealth; or
>
> (ii) in respect of Registered participants under section 63 of this Law; or
>
> (iii) against persons under section 68 of this Law; or
>
> (iv) in relation to offences against this Law; and
>
> (d) to institute and conduct appeals from decisions in proceedings referred to in paragraph (c); and
>
> (e) to exempt persons proposing to engage, or engaged, in the activity of owning, controlling or operating a transmission system or

distribution system forming part of the interconnected transmission and distribution system from being registered as Registered participants; and

(ea) to prepare and publish reports on the financial and operational performance of network service providers in providing electricity network services; and

(eb) to approve compliance programs of service providers relating to compliance by service providers with this Law or the Rules; and

(f) AER economic regulatory functions or powers; and

(g) any other functions and powers conferred on it under this Law and the Rules.

(2) The AER has the power to do all things necessary or convenient to be done for or in connection with the performance of its functions.

(3) However, the AER—

(a) cannot make a transmission determination—

(i) regulating the revenue AEMO earns or may earn; or

(ii) regulating the price of electricity network services provided by AEMO unless the services are shared transmission services provided by means of, or in connection with, a declared shared network; and

(b) cannot regulate by transmission determination or in any other way the price of any other service provided by AEMO, or the amount of any other charge made by AEMO.

38 The final decision was an AER economic regulatory decision (as defined in s 2) arrived at as the result of the AER exercising AER economic regulatory functions or powers (as defined in s 2).

39 Section 16 of the NEL prescribes the manner in which the AER is to perform the AER economic regulatory functions or powers. That section is in the following terms:

16—Manner in which AER performs AER economic regulatory functions or powers

(1) The AER must, in performing or exercising an AER economic regulatory function or power—

(a) perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national electricity objective; and

(b) if the function or power performed or exercised by the AER relates to the making of a distribution determination or transmission determination, ensure that the regulated network service provider to whom the determination will apply, any affected Registered participant and, if AEMO is affected by the determination, AEMO, are, in accordance with the Rules—

(i) informed of material issues under consideration by the AER; and

(ii) given a reasonable opportunity to make submissions in respect of that determination before it is made.

(2) In addition, the AER—

(a) must take into account the revenue and pricing principles—

(i) when exercising a discretion in making those parts of a distribution determination or transmission determination relating to direct control network services; or

(ii) when making an access determination relating to a rate or charge for an electricity network service; and

(b) may take into account the revenue and pricing principles when performing or exercising any other AER economic function or power, if the AER considers it appropriate to do so.

(3) For the purposes of subsection (2)(a)(ii), a reference to a "direct control network service" in the revenue and pricing principles must be read as a reference to an "electricity network service".

(4) In this section—

affected Registered participant means a Registered participant (other than the regulated network service provider to whom the distribution determination or transmission determination will apply) whose interests are affected by the distribution determination or transmission determination.

40 The confidentiality provisions embodied in s 44AAF of the *Competition and Consumer Act 2010* (Cth) (**the Competition Act**) are applied specifically for the purposes of the NEL, the NERegs and the NER *"… as if it formed part of* [the NEL]*"* (see s 18 of the NEL).

41 Section 28D of the NEL provides:

28D—Meaning of regulatory information notice

A regulatory information notice is a notice prepared and served by the AER in accordance with this Division that requires the regulated network service provider, or a related provider, named in the notice to do either or both of the following:

(a) provide to the AER the information specified in the notice;

(b) prepare, maintain or keep information specified in the notice in a manner and form specified in the notice.

42 Section 28ZC of the NEL provides as follows:

28ZC—Consideration by the AER of submissions made to it under this Law

If, under this Law or the Rules, the AER publishes a notice inviting submissions in relation to the making of an AER economic regulatory decision, the AER, in making the decision—

(a) must consider every submission it receives within the period specified in the notice; and

(b) may, but need not, consider a submission it receives after the period specified in the notice expires.

43 Part 4, Div 1 of the NEL contains various provisions governing the functions, powers and operations of the Australian Energy Market Commission (**AEMC**).

44 Part 6 deals with proceedings under the NEL.

45 Part 6, Div 3A contains provisions dealing with merits review of relevant decisions. The Tribunal has power to do all things necessary or convenient to be done for or in connection with the performance of its functions under Pt 6, Div 3A (s 57B of the NEL).

46 Sections 71B, 71C, 71M, 71N, 71O, 71P and 71R are in the following terms:

71B—Applications for review

(1) An affected or interested person or body, with the leave of the Tribunal, may apply to the Tribunal for a review of a reviewable regulatory decision.

(2) An application must—

(a) be made in the form and manner determined by the Tribunal; and

(b) specify the grounds for review being relied on.

71C—Grounds for review

(1) An application under section 71B(1) may be made only on 1 or more of the following grounds:

(a) the AER made an error of fact in its findings of facts, and that error of fact was material to the making of the decision;

(b) the AER made more than 1 error of fact in its findings of facts, and that those errors of fact, in combination, were material to the making of the decision;

(c) the exercise of the AER's discretion was incorrect, having regard to all the circumstances;

(d) the AER's decision was unreasonable, having regard to all the circumstances.

(2) It is for the applicant to establish a ground listed in subsection (1).

…

71M—Interveners may raise new grounds for review

(1) An intervener may raise in a review under this Subdivision any of the grounds specified in section 71C even if the ground that is raised by the intervener is not raised by the applicant.

(2) To avoid doubt, it is for the intervener to establish the ground referred to in subsection (1).

71N—Parties to a review under this Subdivision

The parties to a review under this Subdivision are—

(a) the applicant; and

(b) AER; and

(c) an intervener.

71O—Matters that parties to a review may and may not raise in a review

(1) The AER, in a review under this Subdivision, may raise—

(a) a matter not raised by the applicant or an intervener that relates to a ground for review, or a matter raised in support of a ground for review, raised by the applicant or an intervener;

(b) a possible outcome or effect on the reviewable regulatory decision being reviewed that the AER considers may occur as a consequence of the Tribunal making a determination setting aside or varying the reviewable regulatory decision.

(2) A party (other than the AER) to a review under this Subdivision may not raise any matter that was not raised in submissions to the AER before the reviewable regulatory decision was made.

71P—Tribunal must make determination

(1) If, following an application, the Tribunal grants leave in accordance with section 71B(1), the Tribunal must make a determination in respect of the application.

Note—
See section 71Q for the time limit within which the Tribunal must make its determination.

(2) A determination under this section may—

(a) affirm, set aside or vary the reviewable regulatory decision;

(b) remit the matter back to the AER to make the decision again, in accordance with any direction or recommendation of the Tribunal.

(3) For the purposes of making a determination of the kind in subsection (2)(a), the Tribunal may perform all the functions and exercise all the powers of the AER under this Law or the Rules.

(4) In deciding whether to remit a matter back to the AER to make the decision again, the Tribunal must have regard to the nature and relative complexities of—

(a) the reviewable regulatory decision; and

(b) the matter the subject of the review.

(5) A determination by the Tribunal affirming, setting aside or varying the reviewable regulatory decision is, for the purposes of this Law (other than this Part), to be taken to be a decision of the AER.

…

71R—Matters to be considered by Tribunal in making determination

(1) Subject to this section, the Tribunal, in reviewing a reviewable regulatory decision, must not consider any matter other than review related matter.

(2) The Tribunal, in reviewing a reviewable regulatory decision, must have regard to any document—

(a) prepared, and used, by the AER for the purpose of making the reviewable regulatory decision; and

(b) that the AER has made publicly available.

(3) In addition, if in a review, the Tribunal is of the view that a ground of review has been established, the Tribunal may allow new information or material to be submitted if the new information or material—

(a) would assist it on any aspect of the determination to be made; and

(b) was not unreasonably withheld from the AER when it was making the reviewable regulatory decision.

(4) Subject to this Law, for the purpose of subsection (3)(b), information or material not provided to the AER following a request for that information or material by it under this Law or the Rules is to be taken to have been unreasonably withheld.

(5) Subsection (5) does not limit what may constitute an unreasonable withholding of information or material.

(6) In this section—

review related matter means—

(a) the application for review and submissions in support of the application; and

(b) the reviewable regulatory decision and the written record of it and any written reasons for it; and

(c) in the case of a reviewable regulatory decision that is a network revenue or pricing determination—any document, proposal or information required or allowed under the Rules to be submitted as part of the process for the making of the determination; and

(d) any written submissions made to the AER before the reviewable regulatory decision was made; and

(e) any reports and materials relied on by the AER in making the reviewable regulatory decision; and

(f) any draft of the reviewable regulatory decision; and

(g) any submissions on the draft of the reviewable regulatory decision or the reviewable regulatory decision itself considered by the AER; and

(h) the transcript (if any) of any hearing conducted by the AER for the purpose of making the reviewable regulatory decision.

47 For the purposes of those provisions, a *reviewable regulatory decision* is defined to mean:

> (a) a network revenue or pricing determination that sets a regulatory period; or
>
> (b) any other determination (including a distribution determination or transmission determination) or decision of the AER under the Rules that is prescribed by the Regulations to be a reviewable regulatory decision,

but does not include a decision of the AER made under Pt 3, Div 6.

48 Part 3, Div 6 deals with the disclosure of confidential information provided to the AER.

49 The meaning of the phrase *"unreasonable having regard to all the circumstances"*, as it appears in s 71C(1)(d) was considered by the Tribunal (Middleton J, Deputy President, Mr R Davey and Mr RF Shogren) in *Application by EnergyAustralia and Ors* (2009) ATPR 42-299. After referring to and citing passages from the Full Court decision in *Australian Competition and Consumer Commission v Australian Competition Tribunal* (2006) 152 FCR 33, at [63]–[67], the Tribunal said:

> 63 The Tribunal considers it clear that the scope of the separate ground of review of 'unreasonableness' set out in the NEL goes somewhat beyond the so called Wednesbury unreasonableness ground. To a certain extent, there is an overlap between the exercise of a discretion which is 'incorrect', and a decision which is unreasonable having regard to all the circumstances. If the reasons for a decision contain an element 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.
>
> 64 If 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.
>
> 65 In considering whether the Applicants have established any ground of review, s 71R limits the matters which the Tribunal may consider on its review to 'review related matter' as defined in s 71R(6). It is only if a ground of review is made out that the Tribunal may allow new information or material to be submitted, and then only if it would assist on any aspect of the determination to be made and was not earlier unreasonably withheld from the AER: see s 71R(3). Also, s 71O(2) prevents a party to a review, other than the AER, from raising any matter that was not raised in submissions to the AER before the reviewable regulatory decision was made.
>
> 66 Therefore, the Tribunal's review is not at large, but is a review of the AER's decision on the factual and legal grounds available, but only on the material provided to or before the AER. Nevertheless, the Tribunal must consider the

> merits of whether the material provided to or before the AER leads to a finding or findings of material fact different from those made by the AER, or that it exercised its discretion incorrectly, or that its decision in all the circumstances was unreasonable.
>
> 67 Once the Tribunal is satisfied that a ground of review is established, the Tribunal must consider the various options available under the NEL. One option is to remit the matter to the AER. The Tribunal has already indicated its approach to the appropriateness or otherwise of remitting the matter to the AER: see *Application by EnergyAustralia* (2009) ACompT 7 at [30-38].

50 We agree with the observations extracted at [49] above. We would wish to add that, in our view, the ground of review provided for in s 71C(1)(d) captures the notion of want of reason. That ground is not a mandate for the substitution of the Tribunal's preferred view. The review applicant must establish more than that.

51 In the same case, the Tribunal observed that the grounds of review specified in s 71C(1)(c) and s 71C(1)(d) were separate grounds of review. We also agree with that observation.

52 In a later decision (*Application by ActewAGL Distribution* (2010) ATPR 42-324), the Tribunal (Finkelstein J, President, Mr RF Shogren and Dr JS Marsden), considered a statutory provision (s 245 of the *National Gas Law*) which is in the same terms as s 71C of the NEL. At [30]–[35], the Tribunal explained all of the relevant concepts in the following way:

> 30 During the hearing, there was some discussion about the nature of the review. The grounds seem simple enough: error of fact, incorrect exercise of discretion and unreasonableness. In reality, however, these concepts are not straightforward.
>
> 31 Take the meaning of "fact". A glance at a dictionary shows its meaning to be something which is capable of being experienced or perceived and hence known to be true. On this basis a "fact" is something that actually exists independently of its acknowledgement in the mind of the perceiver.
>
> 32 In *Australian Competition & Consumer Commission v Australian Competition Tribunal* (2006) 152 FCR 33, 73-74 the Full Court gave the word "fact" a much wider meaning. It decided that, in a provision such as s 39 of the *Gas Pipelines Access (South Australia) Act 1997* (SA), which is in the same terms as s 246 of the Law, "facts" include: (1) historical facts; (2) present facts; and (3) an opinion about the existence of a future fact or circumstance (if necessary, we would add a fourth category, namely negative facts). As regards meaning (3), the Tribunal relied upon the decision of McInerney J in *Morley v National Insurance Co* [1967] VR 566, 567 where the question was what constitutes a "fact" for the purpose of s 55 of the *Evidence Act 1958* (Vic), which made admissible certain documents

containing statements by deceased persons intending to establish facts about which they had personal knowledge. McInerney J said that "fact" should be given an expanded meaning. He said the word "fact" should include a statement of opinion by an expert.

33 This is a radical meaning to be given to the word "fact". The generally accepted view is that an opinion is an inference which is drawn from facts. Yet, as Wigmore famously pointed out, there are many instances where it is difficult (if not impossible) to distinguish between "fact" and "opinion". Take the statement: "He was driving on the left hand side of the road". Ordinarily this would be regarded as a statement of "fact". On the other hand a statement that: "He was driving carelessly" would usually be regarded as an expression of an opinion. The difference between the two statements, however, is between a more concrete and specific form of descriptive statement and a less specific and concrete form.

34 Describing the meaning of a discretionary decision is also a difficult matter. The description "discretionary" is often applied to several types of decision making processes. It is most commonly applied to decision making which involves essentially a weighing up of relevant facts. First the decision maker finds the facts. Then the decision maker undertakes a weighing up process which involves taking into account considerations that are found to be relevant, assessing the weight to be given to those considerations so assessed and determining what, as a result of that process, is the right result. Another approach is found in *Norbis v Norbis* (1985-1986) 161 CLR 513, 518. There Mason and Deane JJ described a discretionary decision as one which involves an assessment that calls for "value judgments in respect of which there is room for reasonable differences of opinion, no particular opinion being uniquely right."

35 A test for what is an unreasonable decision in the context of limited merits review has been considered, albeit briefly, by the High Court. In *East Australian Pipeline Pty Ltd v Australian Competition and Consumer Commission* (2007) 233 CLR 229, [80], Gummow and Hayne JJ said that unreasonableness in legislation such as s 246 of the Law is not intended to include the concept of unreasonableness as applied in judicial review proceedings: ie what is often referred to as "Wednesbury unreasonableness". It is, we think, neither possible nor necessary to give an exhaustive definition of what is an unreasonable decision. At one extreme a decision that is arbitrary or capricious will plainly be unreasonable. At the other extreme, it will not be sufficient merely to reach a different decision to the first instance decision maker; in many areas reasonable persons can perfectly reasonably come to opposite conclusions. But, as the High Court indicated in *East Australian Pipeline* (at [80]) the term unreasonable "provides the basis for inferring the presence of one or more of the well established grounds which render a decision 'incorrect'". In other words, if the decision maker fails to call to attention matters he/she is bound to consider or considers matters which are irrelevant, he/she will be acting unreasonably. Reference might also be made in this connection to the Tribunal's comments on unreasonableness in *Application by EnergyAustralia* [2009] ACompT 8 at [63]-[64].

53 In the present review applications, we are content to adopt the approach to the statutory grounds of review recorded at [30]–[35] in *Application by ActewAGL Distribution*.

54 In respect of a number of matters, the AER submitted that those matters may not be raised before the Tribunal because they were not raised in submissions to the AER before the final decision was made (s 71O(2) of the NEL). The AER also submitted that the review applicants have generally failed to meet the requirements of s 71C. Finally, the AER submitted that some of the material now sought to be relied upon by the DNSPs and the interveners is not *review related matter* within the definition of that expression in s 71R(6) and should not be permitted to be relied upon. For these reasons, the Tribunal will need to consider the impact of ss 71B, 71C, 71M, 71N, 71O, 71P and 71R in respect of a number of the issues to be determined in the present review applications.

55 Part 7 of the NEL deals with the making of the NER. One process by which the NER may be made or amended is by means of action initiated by the AEMC.

56 Schedule 1 to the NEL specifies the subject matter for the NER. Matters which may be legitimately made the subject of the NER are the operation of distribution systems and the revenue and pricing of such systems. In addition, the NER may provide for regulatory economic methodologies and the terms and conditions for the provision of electricity network services or any class of electricity services.

57 Schedule 2 to the NEL (*Miscellaneous provisions relating to interpretation*) contains a number of provisions which govern the way in which the NEL, the NERegs and the NER are to be interpreted (see s 3 of the NEL).

58 Clause 1 of Sch 2 provides that the application of the Schedule to the NEL, the NERegs or other statutory instrument (other than the NER) may be displaced, wholly or partly, by a contrary intention appearing in the NEL, the NERegs or the other relevant statutory instrument. Clause 1(2) provides that the application of Sch 2 to the NER (other than cll 7, 12, 15, 17, 19, 23–26, 31–34, 39, 42 and 43) may be displaced, wholly or partly, by a contrary intention appearing in the NER.

59 Clause 7 and cl 8 of Sch 2 to the NEL are in the following terms:

7—Interpretation best achieving Law's purpose

(1) 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.

(2) Subclause (1) applies whether or not the purpose is expressly stated in this Law.

8—Use of extrinsic material in interpretation

(1) In this clause—

Law extrinsic material means relevant material not forming part of this Law, including, for example—

(a) material that is set out in the document containing the text of this Law as printed by authority of the Government Printer of South Australia; and

(b) a relevant report of a committee of the Legislative Council or House of Assembly of South Australia that was made to the Legislative Council or House of Assembly of South Australia before the provision was enacted; and

(c) an explanatory note or memorandum relating to the Bill that contained the provision, or any relevant document, that was laid before, or given to the members of, the Legislative Council or House of Assembly of South Australia by the member bringing in the Bill before the provision was enacted; and

(d) the speech made to the Legislative Council or House of Assembly of South Australia by the member in moving a motion that the Bill be read a second time; and

(e) material in the Votes and Proceedings of the Legislative Council or House of Assembly of South Australia or in any official record of debates in the Legislative Council or House of Assembly of South Australia; and

(f) a document that is declared by the Regulations to be a relevant document for the purposes of this clause;

ordinary meaning means the ordinary meaning conveyed by a provision having regard to its context in this Law and to the purpose of this Law;

Rule extrinsic material means—

(a) a draft Rule determination; or

(b) a final Rule determination; or

(c) any document (however described)—

(i) relied on by the AEMC in making a draft Rule determination or final Rule determination; or

(ii) adopted by the AEMC in making a draft Rule determination or final Rule determination.

(2) Subject to subclause (3), in the interpretation of a provision of this Law, consideration may be given to Law extrinsic material capable of assisting in the interpretation—

(a) if the provision is ambiguous or obscure, to provide an interpretation of it; or

(b) if the ordinary meaning of the provision leads to a result that is manifestly absurd or is unreasonable, to provide an interpretation that avoids such a result; or

(c) in any other case, to confirm the interpretation conveyed by the ordinary meaning of the provision.

(2a) Subject to subclause (3), in the interpretation of a provision of the Rules, consideration may be given to Law extrinsic material or Rules extrinsic material capable of assisting in the interpretation—

(a) if the provision is ambiguous or obscure, to provide an interpretation of it; or

(b) if the ordinary meaning of the provision leads to a result that is manifestly absurd or is unreasonable, to provide an interpretation that avoids such a result; or

(c) in any other case, to confirm the interpretation conveyed by the ordinary meaning of the provision.

(3) In determining whether consideration should be given to Law extrinsic material or Rule extrinsic material, and in determining the weight to be given to Law extrinsic material or Rule extrinsic material, regard is to be had to—

(a) the desirability of a provision being interpreted as having its ordinary meaning; and

(b) the undesirability of prolonging proceedings without compensating advantage; and

(c) other relevant matters.

60 Clauses 11, 12 and 13 of Sch 2 provide as follows:

11—Provisions relating to defined terms and gender and number

(1) If this Law defines a word or expression, other parts of speech and grammatical forms of the word or expression have corresponding meanings.

(2) Definitions in or applicable to this Law apply except so far as the context or subject matter otherwise indicates or requires.

(3) In this Law, words indicating a gender include each other gender.

(4) In this Law—

(a) words in the singular include the plural; and

(b) words in the plural include the singular.

12—Meaning of may and must etc

(1) In this Law, the word “may”, or a similar word or expression, used in relation to a power indicates that the power may be exercised or not exercised, at discretion.

(2) In this Law, the word “must”, or a similar word or expression, used in relation to a power indicates that the power is required to be exercised.

(3) This clause has effect despite any rule of construction to the contrary.

13—Words and expressions used in statutory instruments

(1) Words and expressions used in a statutory instrument have the same meanings as they have, from time to time, in this Law, or relevant provisions of this Law, under or for the purposes of which the instrument is made or in force.

> (2) This clause has effect in relation to an instrument except so far as the contrary intention appears in the instrument.

61 In summary, Sch 2 to the NEL requires that, unless displaced by a contrary intention appearing in the NEL or the NER (as may be appropriate), the following principles are to be applied to the interpretation of the NEL and the NER:

(a) The interpretation that will best achieve the purpose or object of the NEL is to be preferred to any other interpretation. That purpose or object need not be expressly stated in the NEL (cl 7 of Sch 2 to the NEL).

(b) The NEO is the core or fundamental objective of the NEL and, as such, is to be regarded as *"… the purpose or object of the NEL …"* for the purpose of cl 7 of Sch 2 to the NEL.

(c) In the circumstances described in cl 8 of Sch 2 to the NEL, resort may be had to the types of extrinsic material specified in cl 8 as an aid to the interpretation of a provision of the NEL or the NER. Such resort can be had if:

    (i) The relevant provision is ambiguous or obscure; or

    (ii) The ordinary meaning of the provision leads to a result that is manifestly absurd or unreasonable (a result which should be avoided); or

    (iii) To confirm the interpretation that is conveyed by the ordinary meaning of the provision

    and the extrinsic material is capable of assisting in the interpretation. Sub-clause (3) of cl 8 must also be taken into account. That sub-clause is difficult to interpret. In our view, that sub-clause mandates that those charged with interpreting the NEL and the NER must, when considering whether to have regard to extrinsic material, have regard to each of the three matters specified in sub-cl (3). A *"relevant matter"* within the meaning of cl 8(3)(c) is a matter which is to be determined to be relevant in an objective sense.

(d) Clause 7 and cl 8 do not authorise a wholesale redrafting of the relevant provision. The quest is always to find the correct interpretation of that provision, not to embark upon an exposition of the interpreter's view of what the relevant provision should mean.

(e) In the NEL, the meaning of *"may"* and *"must"* is as specified in cl 12 of Sch 2 to the NEL notwithstanding any rule of construction to the contrary.

(f) Except insofar as the contrary intention appears in a particular statutory instrument, words and expressions used in a statutory instrument made under the NEL have the same meaning as they have in the relevant provisions of the NEL.

(g) In the NER, unless the context otherwise requires:

1.7.1 General

…

(a) headings are for convenience only and do not affect the interpretation of the *Rules;*

(b) words importing the singular include the plural and vice versa;

(c) words importing a gender include any gender;

(d) when italicised, other parts of speech and grammatical forms of a word or phrase defined in the *Rules* have a corresponding meaning;

(e) an expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other body corporate and any government agency;

(f) a reference to any thing includes a part of that thing;

(g) a reference to a chapter, condition, clause, schedule or part is to a chapter, condition, clause, schedule or part of the *Rules;*

(h) a reference to any statute, regulation, proclamation, order in council, ordinances or by-laws includes all statutes, regulations, proclamations, orders in council, ordinances and by-laws varying, consolidating, re-enacting, extending or replacing them and a reference to a statute includes all regulations, proclamations, orders in council, ordinances, by-laws and determinations issued under that statute;

(i) a reference to a document or a provision of a document includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document;

(j) a reference to a person includes that person's executors, administrators, successors, substitutes (including, without limitation, persons taking by novation) and permitted assigns;

(k) a period of time:

(1) which dates from a given *day* or the *day* of an act or event is to be calculated exclusive of that *day;* or

(2) which commences on a given *day* or the *day* of an act or event is to be calculated inclusive of that *day*;

(l) an event which is required under the *Rules* to occur on or by a stipulated *day* which is not a *business day* may occur on or by the next *business day*; and

(m) the schedules to the *Rules* form part of the *Rules*.

> It is not intended that any of the following provisions of Schedule 2 to the *National Electricity Law* should apply to the *Rules:*
>
> Clauses 2, 4, 9, 10, 11, 21, 28, 29, 30, 31AH, 35, 36, 37 and 38.
>
> This exclusion is in addition to an exclusion that arises from other provisions of the *Rules* in which an intention is expressed, or from which an intention may be inferred, that a provision of the relevant Schedule is not to apply to the *Rules*.

(h) The interpretation statutes of South Australia and Victoria do not apply to the NEL or to the NER. Nor does the *Acts Interpretation Act 1901* (Cth). The essential governing principles for the interpretation of the NEL and the NER are found in cll 7, 8, 11, 12 and 13 of Sch 2 to the NEL. In our view, it does not assist the task of interpreting the NEL and the NER for the Tribunal to resort to common law principles of statutory construction except (perhaps) as an aid to understanding how to interpret and apply the rules of interpretation laid down in Sch 2 to the NEL.

BUILDING BLOCK DETERMINATIONS

62 The methodology captured by the phrase *building block determination* is laid out in Pt C of Ch 6 of the NER. Although not precisely in point now, the diagrammatic depiction of the process set out at p 20 of the ESCV's final decision published in October 2006 remains generally applicable. A copy of that diagram is attached to these Reasons as Attachment "B".

63 Clause 6.3.1(a) of the NER provides that a *building block determination* is a component of a distribution determination. The procedure for making a *building block determination* is contained in Pt E of Ch 6 and involves the submission of a *building block proposal* to the AER by the particular DNSP (cl 6.3.1(b)).

64 A DNSP's *building block proposal* is required to be prepared in accordance with the *post-tax revenue model* prepared and published by the AER and in accordance with other relevant requirements of Pt C of Ch 6 and Sch 6.1 to Ch 6 (cl 6.3.1(c)(1)). It must also comply with the requirements of, and must contain or be accompanied by the information required by, any relevant *regulatory information instrument* (cl 6.3.1(c)(2)).

65 A DNSP's *post-tax revenue model* must set out the manner in which the DNSP's *annual revenue requirement* for each *regulatory year* of a *regulatory control period* is to be calculated (cl 6.4.2(a)).

66 The contents of that model must include a method that the AER determines is likely to result in the best estimates of expected inflation (cl 6.4.2(b)(1)), the timing assumptions and associated discount rates that are to apply in relation to the calculation of the building blocks referred to in cl 6.4.3 (cl 6.5.3(b)(2)), the manner in which working capital is to be treated (cl 6.4.2(3)) and the manner in which the estimated cost of corporate income tax is to be calculated (cl 6.4.2(4)).

67 Clause 6.4.3(a) of the NER provides:

> **6.4.3 Building block approach**
>
> **(a) 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 schem*e – 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).

68 For a DNSP, the indexation of the regulatory asset base is calculated in accordance with cl 6.5.1 and Sch 6.2. That indexation procedure includes the *roll forward model* (**RFM**) which is explained in cl 6.5.1(e).

69 A DNSP's return on capital is calculated in accordance with cl 6.5.2 of the NER (cl 6.4.3(a)(2) and cl 6.4.3(b)(2)).

70 The revenue increments and decrements (if any) for each *regulatory year* of a *regulatory control period* arising from the application of certain specific schemes are those referred to in cll 6.5.8, 6.6.2 and 6.6.3 (cl 6.4.3(a)(5) and cl 6.4.3(b)(5)). The other revenue increments and decrements (if any) for each year arising from the application of a control mechanism in the previous *regulatory control period* are those that are to be carried forward to the current *regulatory control period* as the 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* (cl 6.4.3(a)(6) and cl 6.4.3(b)(6)).

71 The DNSP's forecast operating expenditure for the year is the forecast operating expenditure as accepted or substituted by the AER in accordance with cl 6.5.6 (cl 6.4.3(a)(7) and cl 6.4.3(b)(7)).

72 The return on capital for each *regulatory year* is calculated by applying a rate of return for the relevant DNSP for that *regulatory control period* to the value of the regulatory asset base for the *relevant distribution system* as at the beginning of that *regulatory year* (cl 6.5.2(a)).

73 The rate of return for a DNSP for a *regulatory control period* is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the *distribution* business of the DNSP and must be calculated as a nominal post tax *weighted average cost of capital (WACC)* in accordance with the formula set out in cl 6.5.2(b).

74 The nominal risk free rate for a *regulatory control period* is the rate determined for that *regulatory control period* by the AER on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of ten years using:

> (1) the indicative mid rates published by the Reserve Bank of Australia; and
>
> (2) a period of time which is either:
>
> > (i) a period (**the agreed period**) proposed by the relevant *Distribution Network Service Provider*, and agreed by the *AER* (such agreement is not to be unreasonably withheld); or
> >
> > (ii) a period specified by the *AER*, and notified to the provider within a reasonable time prior to the commencement of that period, if the

period proposed by the provider is not agreed by the AER under subparagraph (i),

and, for the purposes of subparagraph (i):

(iii) the start date and end date for the agreed period may be kept confidential, but only until the expiration of the agreed period; and

(iv) the *AER* must notify the *Distribution Network Service Provider* whether or not it agrees with the proposed period within 30 *business days* of the date of submission of the *building block proposal*.

(Clause 6.5.2(c))

75 Clause 6.5.2(d) provides that:

(d) If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in paragraph (c)(2), the *AER* must (unless some different provision is made by a relevant *statement of regulatory intent*) determine the nominal risk free rate for the *regulatory control period* by interpolating on a straight line basis from the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date.

76 Under the heading *Meaning of debt risk premium*, cl 6.5.2(e) provides:

(e) The debt risk premium for a *regulatory control period* is the premium determined for that *regulatory control period* by the AER as 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.

77 A *building block proposal* must include the total forecast operating expenditure for the relevant *regulatory control period* which the DNSP considers is required in order to achieve the *operating expenditure objectives*. These are:

(a) Meet or manage the expected demand for *standard control services* over that period;

(b) Comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;

(c) Maintain the quality, reliability and security of supply of *standard control services*; and

(d) Maintain the reliability, safety and security of the *distribution system* through the supply of *standard control services*.

78 These requirements are set out in cl 6.5.6(a) of the NER.

79 The forecast of required operating expenditure of a DNSP that is included in a *building block proposal* must also:

(a) Comply with the requirements of any relevant *regulatory information instrument*; and

(b) Be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in the *Cost Allocation Method* for the DNSP; and

(c) Include both:

(i) The total of the forecast operating expenditure for the relevant *regulatory control period*; and

(ii) The forecast of the operating expenditure for each *regulatory year* of the relevant *regulatory control period* (cl 6.5.6(b)).

80 Subclauses (c), (d) and (e) of cl 6.5.6 of the NER are in the following terms:

> (c) The *AER* must accept the forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast operating expenditure for the *regulatory control period* reasonably reflects:
>
> (1) the efficient costs of achieving the *operating expenditure objectives*; and
>
> (2) the costs that a prudent operator in the circumstances of the relevant *Distribution Network Service Provider* would require to achieve the *operating expenditure objectives*; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*.
>
> (the *operating expenditure criteri*a).
>
> (d) If the *AER* is not satisfied as referred to in paragraph (c), it must not accept the forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal*.
>
> (e) In deciding whether or not the *AER* is satisfied as referred to in paragraph (c) the *AER* must have regard to the following (the *operating expenditure factors*):
>
> (1) the information included in or accompanying the *building block proposal*;
>
> (2) submissions received in the course of consulting on the *building block proposal*;

(3) analysis undertaken by or for the *AER* and *published* before the distribution determination is made in its final form;

(4) benchmark operating expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the *regulatory control period*;

(5) the actual and expected operating expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the total labour costs included in the capital and operating expenditure forecasts for the *regulatory control period* are consistent with the incentives provided by the applicable *service target performance incentive scheme* in respect of 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;

(10) the extent the *Distribution Network Service Provider* has considered, and made provision for, efficient non-network alternatives.

81 A *building block proposal* must include the total forecast capital expenditure for the relevant *regulatory control period* which the DNSP considers is required in order to achieve the *capital expenditure objectives*. These objectives are:

(a) Meet or manage the expected demand for *standard control services* over that period;

(b) Comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;

(c) Maintain the quality, reliability and security of supply of *standard control services*;

(d) Maintain the reliability, safety and security of the *distribution system* through the supply of *standard control services.*

(Clause 6.5.7(a) of the NER.)

82 The forecast of required capital expenditure of a DNSP that is included in a *building block proposal* must also:

(a) Comply with the requirements of any relevant *regulatory information instrument*; and

(b) Be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in the *Cost Allocation Method* for the DNSP; and

(c) Include both:

(i) The total of the forecast capital expenditure for the relevant *regulatory control period*; and

(ii) The forecast of the capital expenditure for each *regulatory year* of the relevant *regulatory control period*; and

(d) Identify any forecast capital expenditure that is for an option that has satisfied the *regulatory test*.

(Clause 6.5.7(b) of the NER.)

83 Subclauses (c), (d) and (e) of cl 6.5.7 of the NER are in the following terms:

> (c) The *AER* must accept the forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast capital expenditure for the *regulatory control period* reasonably reflects:
>
> (1) the efficient costs of achieving the *capital 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 capital expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the *capital expenditure objectives*.
>
> (the *capital expenditure criteria*)
>
> (d) If the *AER* is not satisfied as referred to in paragraph (c), it must not accept the forecast of required capital expenditure of a *Distribution Network Service Provider*.
>
> (e) In deciding whether or not the *AER* is satisfied as referred to in paragraph (c), the *AE*R must have regard to the following (the *capital expenditure factor*s):
>
> (1) the information included in or accompanying the *building block proposal*;
>
> (2) submissions received in the course of consulting on the *building block proposal*;
>
> (3) analysis undertaken by or for the *AER* and *published* before the distribution determination is made in its final form;
>
> (4) benchmark capital expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the *regulatory control period;*

(5) the actual and expected capital expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the total labour costs included in the capital and operating expenditure forecasts for the *regulatory control period* are consistent with the incentives provided by the applicable *service target performance incentive scheme* in respect of the *regulatory control period*;

(9) the extent the forecast of required capital 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;

(10) the extent the *Distribution Network Service Provider* has considered, and made provision for, efficient non-network alternatives.

DRAFT AND FINAL DETERMINATIONS BY THE AER

84 The regulatory process is a "propose/response" process. Each DNSP must lodge a regulatory proposal with the AER and the AER must consider that proposal and pronounce a draft decision in respect of that proposal. Clause 6.12 of the NER lays down very specific requirements in relation to the AER's consideration of a DNSP's regulatory proposal.

85 First, the AER is required to make a decision on the DNSP's current *building block proposal*. By that decision, the AER is either to approve or to refuse to approve the *annual revenue requirement* for the DNSP, as set out in its *building block proposal*, for each *regulatory year* of the *regulatory control period.* In addition, the AER is required either to accept the total of the forecast capital expenditure for the *regulatory control period* that is included in the current *building block proposal* or not to accept the total of the forecast capital expenditure for the *regulatory control period* that is included in the DNSP's current *building block proposal*, in which case the AER must set out its reasons for that decision and provide an estimate of the total of the DNSP's required capital expenditure for the *regulatory control period* that the AER is satisfied reasonably reflects the *capital expenditure criteria*, taking into account the *capital expenditure factors*. The AER is also required to make a decision in which it either accepts the total of the forecast operating expenditure for the *regulatory control period* that is included in the DNSP's current *building block proposal* or does not accept the total of the forecast operating expenditure for that *regulatory control*

period in which case the AER must set out its reasons for that decision and provide an estimate of the total of the DNSP's required operating expenditure for the *regulatory control period* that the AER is satisfied reasonably reflects the *operating expenditure criteria*, taking into account the *operating expenditure factors*. (See cl 6.12.1(2), (3) and (4) of the NER).

86 Other constituent decisions are required to be made by the AER. These are:

(a) A decision in relation to the rate of return (cl 6.12.1(5));

(b) A decision on the regulatory asset base as at the commencement of the *regulatory control period* in accordance with cl 6.5.1 and Sch 6.2 (cl 6.12.1(6));

(c) A decision on the control mechanism (including the X factor) for *standard control services* (to be in accordance with the relevant *framework and approach paper*) (cl 6.12.1(11)); and

(d) A decision on the additional *pass through events* that are to apply for the *regulatory control period* (cl 6.12.1(14)).

87 Clause 6.12.2 of the NER is in the following terms:

6.12.2 Reasons for decisions

The reasons given by the *AER* for a draft distribution determination under rule 6.10 or a final distribution determination under rule 6.11 must set out the basis and rationale of the determination, including:

(1) details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the *AER*; and

(2) the values adopted by the *AER* for each of the input variables in any calculations and formulae, including:

(i) whether those values have been taken or derived from the provider's current *building block proposal*; and

(ii) if not, the rationale for the adoption of those values; and

(3) details of any assumptions made by the *AER* in undertaking any material qualitative and quantitative analyses; and

(4) reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretions, as referred to in this Chapter 6, for the purposes of the determination.

88 Clause 6.12.3 of the NER provides:

6.12.3 Extent of AER's discretion in making distribution determinations

(a) Subject to this clause and other provisions of this Chapter 6 explicitly negating or limiting the *AER's* discretion, the *AER* has a discretion to accept or approve, or to refuse to accept or approve, any element of a *regulatory proposal*.

(b) The classification of services must be as set out in the relevant *framework and approach paper* unless the *AER* considers that, in the light of the *Distribution Network Service Provider's regulatory proposal* and the submissions received, there are good reasons for departing from the classification proposed in that paper.

(c) The control mechanisms must be as set out in the relevant *framework and approach paper*.

(d) The *AER* must approve the *total revenue requirement* for a *Distribution Network Service Provider* for a *regulatory control period*, and the *annual revenue requirement* for each *regulatory year* of the *regulatory control period*, as set out in the provider's current *building block proposal*, if the *AER* is satisfied that those amounts have been properly calculated using the *post-tax revenue model* on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of this Chapter 6.

(e) The *AER* must approve a proposed *regulatory control period* if the proposed period consists of *5 regulatory years*.

(f) If the *AER* refuses to approve an amount or value referred to in clause 6.12.1, the substitute amount or value on which the distribution determination is based must be:

(1) determined on the basis of the current *regulatory proposal*; and

(2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the *Rules*.

(g) The *AER* must approve a proposed negotiating framework if the *AER* is satisfied that it adequately complies with the requirements of Part D.

(h) If the *AER* refuses to approve the proposed *negotiating framework*, the approved amended *negotiating framework* must be:

(l) determined on the basis of the current proposed *negotiating framework;* and

(2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the *Rules*.

89 The AER may, but is not required to, consider any submission made pursuant to an invitation for submissions after the time for making the submission has expired (cl 6.14).

90 In the present case, each DNSP submitted a *regulatory proposal* to the AER. The AER published a draft decision in June 2010. Each DNSP had an opportunity to respond to the AER's draft decision. As mentioned at [1] above, the AER published its final decision on 29 October 2010.

ISSUE 1—PUBLIC LIGHTING ISSUES

91 The parties interested in these issues are the members of the SGC and all of the DNSPs. The leave granted to SGC on 18 February 2011 was confined to making submissions based on review related matter in relation to the following issues:

(a) The quantum and structure of the operations, maintenance, repair and replacement (**OMR**) charges for public lighting allowed by the AER;

(b) The methodology used by the AER for determining the quantum and composition of the OMR charges for public lighting;

(c) The funding of replacement public lighting; and

(d) The service classification to apply to public lighting services.

92 On 28 February 2011, SGC filed and served its Outline of Submissions. The AER responded to that outline with a Written Submission filed and served on 10 March 2011. The DNSPs filed and served a joint submission dated the same day. On 3 June 2011, SGC gave notice of a desire to expand its submissions when it served a document styled *"Expanded Submissions of Streetlight Group of Councils"*.

93 Section 71R of the NEL provides that, subject to the terms of that section, in reviewing a reviewable regulatory decision, the Tribunal must not consider any matter other than review related matter. *Review related matter* is defined in subs (6). If a ground of review has been established, the Tribunal may have regard to additional material provided it was not unreasonably withheld from the AER (s 71R(3)–s 71R(5)).

94 The AER and the DNSPs submitted that a significant amount of material now sought to be relied upon by SGC was not *"review related matter"*. At the hearing, the AER provided to the Tribunal a revised list of 23 items which it submitted were not *review related matter*. The material in that list was placed into a separate folder for ease of reference. Ultimately, SGC conceded that the material in that separate folder was material that was not before the AER when it made the final decision. SGC was therefore driven to rely upon s 71R(3) in order to get the material in that folder before the Tribunal. The Tribunal reserved to this Decision the question of whether any of the material in the separate folder (ie the material to which objection was taken) would be allowed to be submitted to the Tribunal. SGC ultimately abandoned reliance on the documents in the separate folder.

95 Chapter 19 of the final decision deals with public lighting. In its Introduction to Ch 19, the AER said:

> Under clause 6.2.2 of the National Electricity Rules (NER), the AER may classify direct control services as either standard or alternative control services.
>
> In its Framework and Approach paper, the AER classified the Victorian DNSPs' provision of operation, maintenance, repair and replacement (OMR) of public lighting as an alternative control service. [Clause 6.8.1 of the NER requires the AER to publish a framework and approach paper prior to every distribution determination. The paper must include details of the AER's control mechanism for each alternative control service.]. Chapter 2 sets out the classification of services for the 2011–15 regulatory control period.
>
> Clause 6.2.5 of the NER requires the AER, in its distribution determination, to impose controls (a control mechanism) over the prices of direct control services and/or the revenue to be derived from these services. Clause 6.2.5(d) of the NER outlines the factors the AER must have regard to in determining the type of control mechanism to apply to alternative control services. One option the AER may apply, and which it did apply, in respect of public lighting, is a cap on the prices of individual services. [See clause 6.2.5(d) of the NER.]
>
> Clause 6.12.3(c) of the NER provides that the control mechanism to be applied in a distribution determination must be as set out in the AER's Framework and Approach paper.
>
> Clauses 6.12.1(12) and 6.12.1(13) of the NER require the AER to make constituent decisions on the control mechanism for alternative control services and how compliance with that control mechanism is to be demonstrated, respectively.

96 The AER noted that, in the financial model created by the ESCV in 2004, OMR charges were derived from the DNSPs' public lighting opex and capex each year.

97 At pp 835–836 of the final decision, the AER said:

> The AER adopted the ESCV's model in 2009, but amended some inputs to accommodate the entry of T5 energy efficient luminaires. [AER, *Energy efficient Public Lighting Charges–Final Decision*, February 2009. This also included removing T5 ballast from an operating expenditure to a capital expenditure item.] This included an OMR charge for T5s which was sought by councils seeking to reduce public lighting energy consumption (and therefore overall costs). Generally however, the model remained consistent with the 2004 version.
>
> The AER updated the public lighting model in 2009 to enable the Victorian DNSPs to forecast public lighting opex and capex for the forthcoming regulatory control period. By incorporating these forecasts, OMR charges are generated for each year of the 2011–15 regulatory control period.
>
> The model was also adjusted to ensure that during the 2011–15 regulatory control period, the Victorian DNSPs can recover capex on luminaires in 2009 and 2010 which has not yet been recovered from customers. [Under the 2004 edition of the model, 2009 capex would have been recovered in 2011 OMR charges, while 2010 capex would have been recovered in 2012 OMR charges.] By permitting and

> smoothing the recovery of this capex over the five year period of 2011–15, customer price shock will be minimised.
>
> The model also reflects the ongoing costs faced by the Victorian DNSPs in dealing with intermittent failures and breakdowns of luminaires and other public lighting components as they occur. It therefore reflects the materials costs associated with spot replacement of various public lighting components. Importantly however, the model does not reflect the costs of materials based on a mass rollout of lighting technology.
>
> Due to the AER's change of approach, the materials input costs proposed by the Victorian DNSPs now represent their actual or forecast costs. This takes into account each DNSP's particular circumstances, rather than the benchmark costs applied in the 2004 (and updated 2009) model.
>
> In making its current assessment on input costs, the AER will allow for some potential differences between the services provided by each DNSP, and the input costs faced by each DNSP. Accordingly, the AER accepts that each DNSP may apply a different cost to the same input (for example, lamps).
>
> The AER will accept the Victorian DNSPs' revised proposals where sufficient evidence is provided to the AER to justify input costs which have been adjusted from those established in the ESCV's 2004 decision and the AER's 2009 public lighting decisions. [ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004; AER, *Energy efficient Public Lighting Charges–Final Decision*, February 2009] The AER considers that this approach is consistent with the revenue and pricing principles (RPP) in s. 7A of the NEL and the National Electricity Objective (NEO) in s. 7 of the NEL.
>
> Therefore, input costs for items, such as luminaires, lamps and ballasts, as well as failure rates for various components, are assessed by the AER on their merits. The ensuing approved input rates generate the OMR charges for each Victorian DNSP. In recognition of this, the 2009 model removed the 10 per cent buffer applicable to OMR charges under the 2004 model.

98 At pp 892–893 of the final decision, the AER summarised its conclusions in respect of the public lighting expenditure forecasts and associated charges proposed by each of the DNSPs. The AER said:

> The AER has assessed the public lighting expenditure forecasts and associated charges proposed by each of the Victorian DNSPs. The AER has assessed the forecast expenditure including conducting an assessment of the reasonableness of each of the labour, materials and other cost inputs for the forecast opex and capex.
>
> As set out in this chapter, the AER has accepted SP AusNet's revised labour rates and also approved CitiPower and Powercor's originally proposed labour rates. The AER has maintained the labour rates for the other Victorian DNSPs as set out in its draft decision. The AER has adopted the labour escalators from appendix K of this final decision.
>
> The AER has accepted the patrol and elevated platform vehicle cost increases as proposed by CitiPower, Powercor and SP AusNet.
>
> The AER has not accepted the Victorian DNSPs' revised materials cost escalators and has instead adopted the escalators from appendix K of this final decision.
>
> The AER also accepted the revised T5 luminaire cost for CitiPower and Powercor.

> The AER has not accepted CitiPower's and Powercor's revised traffic management costs on the basis that these costs do not represent efficient costs in accordance with the NFL. Further, the AER did not receive sufficient information to be convinced that the draft decision traffic management unit costs should be amended for the final decision.
>
> The AER has not accepted the Victorian DNSPs' proposals for higher MV80 and T5 failure rates. In adopting the statistical information provided by SP AusNet, the AER has revised its failure rates of MV80 lights. The AER has also updated the draft decision failure rates for T5 lights taking into account more recent information from VSPLAG.
>
> The AER accepts SP AusNet's proposed 'living away from home' costs allowances, noting that SP AusNet would be obliged to pay crews working in rural and remote areas an allowance to cover accommodation and meals when required to stay overnight. The AER notes that this may be more efficient than having crews return to a depot and then back to the same or similar work location on the following day.
>
> The AER also maintained its draft decision to provide each Victorian DNSP with \$100 000 per annum in GIS costs for the maintenance of their public lighting inventory data.
>
> The AER's concludes that SP AusNet's revised replacement volumes of luminaires, poles and brackets represent efficient capex requirements for the forthcoming regulatory control period, in accordance with the RPP, and in particular, s. 7A(2) of the NEL.
>
> The AER also accepted CitiPower's and Powercor's revised cost for poles and brackets based on information from suppliers' quotations.
>
> The AER also accepted JEN's and SP AusNet's revised volumes for the forecast replacement of MV80 lights with T5 lights during 2011–15.
>
> The AER maintained its draft decision not to accept SP AusNet's proposal that it funds \$94.55 of the cost of T5 lights, including those which replace MV80 lights. Accordingly, the AER has removed this \$94.55 cost component from SP AusNet's capex requirements.
>
> The AER has adopted the WACC and CPI used in other parts of this final decision.
>
> In accordance with clause 6.12.1(12) of the NER, the control mechanism that will apply to the Victorian DNSPs' public lighting services is a cap on the charges for each year of the forthcoming regulatory control period. In accordance with clause 6.12.1(13) of the NER, the Victorian DNSPs' compliance with the control mechanisms for public lighting services is to be demonstrated through the annual pricing proposals.

99 The DNSPs accepted the AER's conclusions. SGC did not.

SGC's Contentions

100 SGC submitted that:

(a) Despite there being no material change in services provided by the DNSPs, the AER approved increases in OMR charges. They are said to be *"excessive"*.

(b) Capex charges had been removed from OMR charges as long ago as 1993 but were re-introduced in 2004 by the ESCV. The AER adopted the approach taken by the ESCV. This approach is flawed.

(c) The AER's modelling is flawed because:

(i) It allowed capital charges by DNSPs for depreciation and interest for replacement lights even though the DNSPs did not fund the cost of replacement lights. The capital cost of replacement lights is funded directly by customers via a component in the OMR charges;

(ii) The AER allowed inappropriate and excessive cost component inputs including PE cells, lamps, luminaires, labour rates, geographical information system (**GIS**), overhead allocations and other components.

(d) The AER models did not establish a separate OMR charge for DNSPs to ***maintain*** lights installed directly by public lighting customers or their contractors.

(e) The AER failed to require the DNSPs to establish OMR charges in a way which is consistent with cl 2.1(c) of the Victorian Public Lighting Code (**PLC**) by minimising costs to public lighting customers.

(f) The AER should have determined that the cost of replacement lights is opex not capex. The capital component of the OMR charges is actually an operating expense disguised as capital.

(g) The AER failed to determine OMR charges that took account of the funding of new light installations by persons other than the DNSPs. The members of SGC had funded some lights. Only the T5Zx14w lights were appropriately recognised. SGC (and VicRoads) should not be required to pay in their OMR charges a sum of money to provide for the eventual replacement of new public lighting which is provided free of charge to the DNSPs. The customers (including SGC) have been providing to the DNSPs a return on capital which has never been outlaid by the DNSPs. This is made worse for the 2011–2015 regulatory period because capex is to be calculated not on the basis of actual expenses but upon the basis of forecast costs. (The AER rejected these submissions. It said that they were based upon questionable assumptions re asset ownership.)

(h) The AER failed to consider that the market for OMR and other public lighting services could be made more contestable and failed to consider how the control mechanism might influence that potential. The AER failed properly to consider tiered pricing.

(i) The AER failed to take into account that it is the customers and not the DNSPs which decide upon the replacement light types and the type of technology involved. This circumstance affects the determination of whether the OMR will be treated as an *alternative controlled distributive service* or a *negotiated distribution service.*

(j) The AER took into account a claim by the DNSPs for accelerated recoupment of the cost of residual life for the early retirement of MV80 lights even though the DNSPs have not invested in such lights. Members of SGC who wish to replace MV80 lights with T5 luminaires are required to pay the full capital and installation costs of the new T5 lights and, in addition, to pay to the DNSP the written down value of the MV80 lights which have been replaced before the end of their useful life. This is wrong because, for the most part, the DNSPs will not have paid for the original cost of the installation of the MV80 lights or their replacement until now.

(k) The AER allowed an excessive GIS component as distributors already receive payment for maintaining inventory and light type data. GIS was never intended to be used in this way. It was originally allowed for system development costs and has long since become redundant.

(l) The AER has failed to adhere to its May 2009 Framework and Approach Paper. The AER failed to check materials costs submitted by the DNSPs.

(m) All of the above matters lead to the ultimate conclusion that the AER erred in its application of the NEL and the NER.

Decision

101 The AER and the DNSPs submitted that SGC could not now run an argument that the costs of replacement lights is opex not capex because it did not put that argument to the AER before the AER made its final decision. The AER and the DNSPs said that SGC was prevented from putting such an argument now by s 71O(2) of the NEL.

102 Senior Counsel for SGC conceded that *"… it was not argued specifically that those costs should be treated as opex not capex"*. Nonetheless, he submitted that, in general terms, the DNSPs' return on capital was in issue and that this particular contention was picked up or captured by that more general issue.

103 We do not agree.

104 There are good reasons why the Tribunal is not permitted to deal with matters (including submissions and arguments) not raised in submissions before the AER. The AER is the regulator. The Tribunal is the reviewing authority, not the regulator. A review by the Tribunal is limited to the grounds specified in s 71C. It is not a full-blown reconsideration of the AER's decision equivalent to a hearing *de novo*. The legislature intended to ensure, as far as possible, that the regulation of the industry did not become mired in endless decisions and reconsiderations. In any event, even if we are wrong about the availability of this argument, it is quite clear that SGC was not given leave to raise this point. For these reasons, we do not propose to consider this particular submission or the material relied upon in support of it.

105 Before moving to deal with each of SGC's remaining contentions, we note the following matters which are of general importance in dealing with the public lighting issues:

(a) In each Final Determination made in respect of the DNSPs, the AER classified the OMR for the DNSPs' public lighting assets as *"alternative control services"*. An *alternative control service* is a *distribution service* that is a *direct control service* but not a *standard control service* (see Ch 10 Glossary in the NER). A *direct control service* is a *distribution service* that is a *direct control network service* within the meaning of s 2B of the NEL. The effect of the AER classifying the OMR in this way was that the AER determined that the charges made by the DNSPs for the operation, maintenance, repair and replacement of public lighting was for the provision of an *alternative control service* within the meaning of the NER.

(b) This classification was not a contentious issue throughout the regulatory process. In both its Framework and Approach Paper and its draft decision, the AER classified the OMR of the DNSPs ***existing*** public lighting assets as *alternative control services*.

(c) On the other hand, ***new*** public lighting assets (ie new lighting types not subject to a regulated charge and new public lighting at "Greenfield" sites) were classified in the final decision as *"negotiated distribution services"*. The difference between this classification and the classification of existing assets was addressed in the draft decision. *Negotiated distribution services* are not included in the *building block model*. Costs associated with these services are not included in opex or capex forecasts and prices are not set for *negotiated distribution services*.

(d) Most of the challenges made by SGC to the final decision concern charges for public lighting services that were classified by AER to be *alternative control services.*

106 The substance of that part of the final decision which deals with public lighting is:

(a) In order to comply with cl 6.12.1(12) of the NER, the appropriate control mechanism to apply to public lighting services provided by each DNSP is the imposition of a cap on the prices of individual services in each *regulatory year* of the *regulatory control period* and price paths for the remaining years of the r*egulatory control period*; and

(b) In order to adhere to the requirements of cl 6.12.1(13), each DNSPs' compliance with the control mechanism for public lighting services is to be demonstrated through the annual pricing proposal process and is to be consistent with the AER's decision for the relevant regulatory year.

107 SGC suggests that those decisions made by the AER are infected by errors of fact, incorrect exercise of discretion and the making of unreasonable decisions along the way.

108 Clause 6.2.5(d) of the NER requires the AER and the Tribunal, when deciding on a control mechanism for *alternative control services*, to have regard to (*inter alia*) the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination and the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction).

109 In 2004, the ESCV published a financial model to test the veracity of the DNSPs' proposed public lighting OMR charges. That model was the result of extensive consultation which had begun in 2003 among public lighting customers (including councils) the DNSPs and the ESCV.

110 The following observations may be made about the ESCV's 2004 model in relation to public lighting:

(a) The ESCV determined that public lighting was *"an excluded service"*;

(b) OMR charges were derived from the DNSPs' public lighting opex and capex each year;

(c) The model deployed benchmark assumptions about the input costs of materials such as luminaires, photoelectric cells (**PE cells**), ballasts and the annual failure rates of those components over their working life. These were added to labour costs in order to derive OMR charges. The OMR charge was for the DNSPs to recover opex spent on maintaining public lighting assets and replacing failed light components each year;

(d) The model also recognised that, as the DNSPs incurred capex on luminaires, poles and brackets, this capex would go into the public lighting regulatory asset base (**RAB**). Such expenditure was recovered through a return of capital and depreciation according to the weighted average cost of capital (**WACC**) established by the ESCV. In this way, OMR charges would increase as the RAB increased.

(e) The model had an element of imprecision because it did not capture the individual operating characteristics of each DNSP. To accommodate this, the ESCV set benchmark unit rates in the model but would approve DNSPs' proposed OMR changes that were up to 10% above the OMR charges derived from the model; and

(f) The upshot of this process was that the ESCV was approving the DNSPs' OMR charges, rather than approving their respective input costs. The DNSPs could adjust the input costs in the model so long as their proposed OMR charges were no more than 10% above charges predicted by the model.

111 In February 2009, the AER adopted the ESCV's 2004 model but amended some elements in order to accommodate the entry of T5 energy efficient luminaires for use in public lighting. The 2009 decision was the result of a review of the relevant input costs pertinent for a T5 luminaire and the associated OMR charge for a T5 luminaire. Generally speaking, the AER's 2009 model remained consistent with the ESCV's 2004 version. There was no appeal from or challenge to the AER's 2009 decision.

112 Consistent with the requirements of the NER, the final decision required the DNSPs to forecast their actual public lighting opex and capex for the forthcoming regulatory control period rather than requiring the AER to conduct an *ex post* review of actual costs incurred.

113 For this reason, the AER required the DNSPs to submit their current actual input costs and specific circumstances so that the AER could make its decision on costs for each individual DNSP, rather than using the benchmark costs applied in the 2004 model. In late 2009, the AER consulted with the DNSPs on the relevant inputs for the public lighting model. In that way, existing 2010 inputs used to approve OMR charges for 2010 could be amended by the DNSPs for the 2011–2015 regulatory control period. If the DNSPs considered they were incurring, or likely to incur, additional input costs not already included in the model, they could also submit these costs for assessment by the AER. The model in the AER's final determination did not utilise the 10% buffer applicable to OMR charges under the ESCV's 2004 model because it did not rely on benchmark costs.

114 In making its constituent decisions in respect of public lighting for the 2011–2015 distribution determination, the AER accepted that each DNSP may apply different costs to the same input (for example, lamps). The AER accepted the DNSPs' revised regulatory proposals in those cases where sufficient evidence was provided to the AER to justify input costs which had increased from those established in the ESCV's 2004 decision and the AER's 2009 public lighting decision. The AER considered that this approach was consistent with the RPP and the NEO.

115 Therefore, for the 2011–2015 distribution determination, input costs for items such as luminaires, lamps, PE cells and ballasts, as well as failure rates for each component, were assessed by the AER on their merits in respect of each DNSP and the material provided in support. The ensuing approved input rates generated the OMR charges for each DNSP.

116 SGC contended that there should be no return to the DNSPs contained in the OMR charges for replacement lighting expenditure because the DNSPs do not fund that expenditure. SGC suggested that that expenditure was actually funded by the customers (including SGC). The contention on this point advanced by SGC is difficult to grasp. It seemed that SGC was arguing that, as the capital costs associated with replacement lighting were directly funded by customers, those costs should not be included in the RAB by

reference to which capital allowances are assessed. Yet, inherent in this submission, is an acknowledgement that the applicants actually pay the costs of replacement lighting but obtain funds on account of those costs through tariffs which they charge their public lighting customers. If DNSPs did not pay the capital costs of replacement lights, those costs could not have been funded through the OMR charges. Where lighting for which the DNSPs did not pay has been included in the RAB, it has been included at zero dollars.

117 In the end, it seems to us that SGC is attempting to revisit an argument which it had previously raised with the ESCV and lost. As the DNSPs submitted, it is inappropriate for the AER or the Tribunal to revisit components of the RAB going back many years when the assumption of the NER is that the RAB will be fixed at the commencement of each regulatory control period and then operated upon as required by reference to DNSPs' forecasts.

118 Fundamental to SGC's contentions in this regard is the proposition that, if the final decision is correct, to some extent they will be paying twice for the same replacement lights. In order to make good this proposition, SGC must demonstrate that payments made by customers through the OMR charges in a previous regulatory control period somehow relate to replacement lights installed during the current regulatory control period. SGC has not made good this proposition. In particular, we do not see how the letters from the State Electricity Commission of Victoria to the Town Clerk of the Shire of Alberton dated 7 April 1993 and 11 June 1993, which SGC relied upon in support of its contentions, bear upon the issue at hand.

119 SGC contends that the AER did not establish OMR charges in a way which is consistent with cl 2.1(c) of the PLC. However, SGC failed to make good the proposition that the AER was bound to apply the PLC. As was submitted by the AER, it was open to it to have regard to the PLC when it made its constituent decisions on public lighting given that the PLC imposes regulatory requirements upon the DNSPs, but it was not obliged to do so. The AER submitted that its decision was consistent with the requirements of the PLC and we are not persuaded otherwise.

120 SGC also submitted that the AER erred in allowing payments in respect of the written-down value of MV80 lighting which was being and would be replaced in the T5

retrofitting process. But, some of the MV80 lighting was being and would be retired ahead of its planned obsolescence because of the requirement that energy efficient lighting be introduced. The effect of this requirement is that, if the DNSPs do not receive payment for the written-down value of the retired MV80 lighting, they will have funded that lighting without receiving a fair economic return. We do not think that SGC's claim in this regard has any merit whatsoever.

121 SGC also argued that the fundamental classification of services adopted by the AER was erroneous. It argued that OMR services should have been classified as *negotiated distribution services* in the same way that the alteration and relocation of DNSP public lighting assets and new public lighting assets were classified as negotiated distribution services. As noted at [95]–[97] and [105] above, the AER had good reason for classifying these services in the way that it did. It was consistent with the regulatory approach adopted by the ESCV and was reflected in the AER's Framework and Approach Paper. SGC asserted that the adoption of two separate classifications would be problematic or potentially problematic but was unable to make good that assertion with any argument or evidentiary material.

122 SGC also submitted that the AER erred by failing to adopt the SGC submission that a tiered pricing structure should be introduced. As the DNSPs submitted, the basis for SGC submission appeared to lie in concerns under competition legislation, the suggested need for effective recognition of capital financing and the alleged pressure placed on councils to vest lighting assets in the applicant. The competition law concerns were never identified, the capital financing issue is a reprise of the arguments referred to above in terms of funding and the allegation that the DNSPs effectively require vesting of lighting assets was rejected.

123 SGC also submitted that the AER allowed excessive input costs. It simply failed to make good that submission.

124 SGC contended that the AER had allowed excessive amounts for GIS. This was not how SGC's challenge to GIS had been put to the AER. It cannot be put this way now, for the first time. Before the AER, SGC had argued that the DNSPs had already received payment for maintaining the relevant information by way of a NUOS charge. The AER considered and rejected this argument. The NUOS charge covered the costs of energy consumption only

and did not include any amount for GIS. The challenge by SGC to the inclusion of a charge for GIS fails.

125 In our view, SGC has failed to make out any of the grounds for review which it is entitled to argue and which were the subject of leave. There will, therefore, be no variation to any of the determinations in respect of public lighting.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

ISSUE 3—CLOSEOUT OF THE ESCV'S "S" FACTOR SCHEME

Introduction

200 The protagonists in respect of this issue are the AER and the Minister, on the one hand, who both seek to defend the AER's decision on this matter, and SP AusNet and UED, on the other hand, who both seek to overturn that decision. The single ground of challenge is that the AER did not have power to do what it did. If that ground is made out, there may be consequences for other DNSPs. The remaining DNSPs (CitiPower, Powercor and JEN) were

content with the AER's decision on this point and will argue, if it becomes necessary to do so, that the Tribunal cannot interfere with the distribution determinations in respect of them on this ground because no challenge to those determinations on this ground has been made by any of those three DNSPs.

201 UED also seeks to have this component of the final decision set aside in its judicial review proceedings.

The Victorian Position for the 2006–2010 Period

202 The tariffs that UED was permitted to charge for the 2006–2010 regulatory period were established by a price determination made by the ESCV on 18 October 2005 (**the last ESCV price determination**).

203 Pursuant to cl 2.1.1 of the last ESCV price determination, a distribution business was prohibited from charging more than the amount that had been calculated on the basis of the distribution tariffs that had been verified by the ESCV in writing to be compliant with the distribution price control formula in cl 2.3.2 of that determination.

204 The price control formula set out in cl 2.3.2 of the last ESCV price determination controlled the prices that could be charged by DNSPs in the period 2006–2010 through a tariff basket price control mechanism. The particular tariff basket price control in use in that determination regulated the tariffs for a basket of services where the individual tariffs for each service was not directly controlled but where an overall constraint was imposed on the weighted average of all of the tariffs that made up the basket. The tariffs that made up the basket in the year for which prices were being set (t) were constrained by the previous year's (t – 1) tariffs adjusted for the annual percentage change in CPI, an X factor, an L factor to recover licence fees and an S factor.

205 The distribution price control formula was set out in cl 2.3.2 of the last ESCV price determination as follows:

$$(1+CPI_t)(1-X_t)L_tS_t \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}}$$

206 The above formula limited the average price increase on the right hand side to less than or equal to the constraints on the left hand side. S_t is the service adjustment in calendar year t for a given distribution business determined in accordance with cl 2.3.9 of the last ESCV price determination.

207 The service adjustment (S_t) was calculated in accordance with the following formula and cl 2.3.9 to cl 2.3.11 of the last ESCV price determination:

$$S_t = \frac{(1+S_t^{'})}{(1+S_{t-6}^{'})}$$

where:

$$S_t^{'} = S_t^{''} - S_{bank,t} + S_{bank,t-1} * (1 + pretaxWACC_D)$$

$$S_t^{''} = \sum_r \sum_n s_t^{r,n}(GAP_{t-2}^{r,n} - GAP_{t-3}^{r,n})$$

$S_{t-6}^{'}$ (a) if *calendar year* t is prior to the *calendar year* ending 31 December 2012:

$$S_{t-6}^{'} = \frac{S_{t-6}}{1 - X_{0,S}}$$

where:

S_{t-6} is the value of S_t calculated for the *calendar year* $t-6$ in accordance with clause 2.3.8(ii) of the price controls dated September 2000, and as set out in Attachment 8;

$X_{0,S}$ is the value of X_t for the *calendar year* 2006, calculated exclusive of the impacts of the S-factor, as set out in clause 2.3.9(iii);

(b) if *calendar year* t is after the *calendar year* ending 31 December 2011, is the value of $S_t^{'}$ calculated for the *calendar year* $t-6$ in accordance with this clause;

r (a) if *calendar year* t is prior to the *calendar year* ending 31 December 2008, refers to the following indicators: *unplanned interruption frequency, unplanned interruption duration, planned minutes off supply*;

(b) if *calendar year* t is after the *calendar year* ending 31 December 2007, refers to the following indicators: *unplanned interruption frequency, unplanned minutes off supply, momentary interruption frequency* and *call centre performance*;

n	refers to the following *network types – CBD, urban* and *rural* as defined in Attachment 1, except for the indicator *call centre performance* when it refers to the *distribution system*;

pretax $WACC_D$ is as set out in Attachment 4;

$s_t^{r,n}$	is the incentive rate for indicator r and *network type* n in *calendar year* t as set out in Attachment 5;
$GAP_{t-2}^{r,n}$	is the performance gap for indicator r and *network type* n in *calendar year* $t-2$ and is calculated in accordance with clause 2.3.10;
$GAP_{t-3}^{r,n}$	is the performance gap for indicator r and *network type* n in *calendar year* $t-3$ and is calculated in accordance with clause 2.3.11;
$S_{bank,t}$	is the amount of the service adjustment that is to be deferred from *calendar year* t and is determined in accordance with clause 2.3.12; and
$S_{bank,t-1}$	(a) if *calendar year* $t-1$ is after *calendar year* ending 31 December 2005, is the amount of the service adjustment that has been deferred from *calendar year* $t-1$; and (b) if *calendar year* $t-1$ refers to the *calendar year* ending 31 December 2005, is equal to zero.

(iii) The values of $X_{0,S}$ are:

AGL Electricity Limited	= 0.038
CitiPower Pty	= 0.088
Powercor Australia Limited	= 0.178
SPI Electricity Pty Limited	= 0.091
United Energy Distribution Pty Limited	= 0.148

(**ESCV S Factor Scheme**)

208 The ESCV S Factor Scheme compared a DNSP's performance between target and actual performance two years previously to year t (t – 2) with a DNSP's performance between target and actual performance three years previous to year t (t – 3) in relation to:

- Minutes off supply (unplanned SAIDI);
- Sustained supply interruption frequency (unplanned SAIFI);
- Momentary supply interruption frequency (MAIFI); and

- Call centre performance.

209 The result of the application of the ESCV S Factor Scheme was that the DNSP's weighted average price cap for year t was increased or decreased based on the difference between actual and target performance for an indicator r and a network type n in years t – 3 and t – 2.

210 The S Factor mechanism looked backward at past performance to make the following adjustments:

- A price increase in year t would occur if the performance of the particular DNSP exceeded target in year t – 2 by more than performance exceeded target in year t – 3. In that event, the S_t term will be greater than one, reflecting the improved performance between years t – 3 and t – 2.
- By reason of a t – 6 term, a price change that took place six years previously was taken into account in the S Factor adjustment in year t.

211 The application of the scheme meant that the allowed price level in any particular year (say 2010) depended upon performance relative to target two and three years earlier (2008 and 2007) and the reversal of any price change six years earlier (2004).

212 The thinking that underpinned the ESCV S Factor Scheme was that it was in the long term interests of consumers of electricity that incentives and disincentives be built into the regulatory system in order to encourage DNSPs to exceed forecast performance criteria and to discourage DNSPs from failing to meet those criteria. It was no doubt thought by the ESCV that, absent the imposition of such incentives and disincentives, DNSPs who enjoyed a natural monopoly in their particular allocated geographical areas may not provide their distribution services in the most cost effective, efficient and appropriate way.

213 The last ESCV price determination expired, according to its terms, on 31 December 2010. It was known at all relevant times to those responsible for making the NER that the last ESCV price determination would expire on that date. No doubt this is why provision was made in 2007 for the AER to take over from the ESCV the management and administration of that price determination. Had regulation of the DNSPs continued on a State basis post

31 December 2010, no doubt the ESCV S Factor Scheme would also have continued beyond that date.

The AER's Decision

214 In its Framework and Approach Paper, the AER flagged that it proposed to carry over any adjustments arising from the ESCV S Factor Scheme that would have applied in the 2011–2015 regulatory period had the scheme continued. The AER said that it would address these adjustments through the revenue building block approach in accordance with Ch 6, Pt C of the NER.

215 In its draft decision, the AER proposed a methodology for closing out the ESCV S Factor Scheme in the regulatory control period 2011–2015 whereby, in each of those years, an amount would be added or subtracted from the building blocks as part of the proposed close out mechanism.

216 In its revised regulatory proposal, UED proposed that the ESCV S Factor Scheme should cease to apply at the end of the then current regulatory period (viz 31 December 2010) and not have any effect in the new regulatory period commencing on 1 January 2011. UED also submitted that the ESCV S Factor Scheme operating during the period 2006–2010 did not give rise to any revenue increments or decrements for inclusion in the building blocks for the regulatory period 2011–2015. It followed from the above submissions that no close out amount for the ESCV S Factor Scheme should be included in the building blocks for the regulatory period 2011–2015 and that the approach flagged by the AER in its Framework and Approach Paper was impermissible. SP AusNet also criticised the approach of the AER although it did not raise, at this point in time, the argument that the AER did not have power to include an S Factor adjustment in the building blocks.

217 On 12 October 2010, UED wrote to the AER. In its letter, UED contended that the AER did not have power to include such an adjustment. UED provided the Advice of Senior Counsel. In that Advice, Senior Counsel said:

> **UED's Position**
>
> 15. UED argues that the AER lacks power to utilise the building block approach through clause 6.4.3(a)(6) of the NER because the ESCV's S Factor implementation mechanism can only be applied in the period 2006-2010 and the output of the S Factor formula is not carried forward. The S Factor

> formula provides an outcome in the year in which it is applied (year t) as a result of comparing the performance in year t–2 with the performance in year t–3. The St term controls prices in year t. It does not control prices, let alone produce a revenue increment or decrement, that is carried forward.
>
> **Opinion**
>
> 16. The S Factor Scheme provides for an adjustment in the year in which it is applied by reference to prior years' performance. It does not require any adjustment in future years by reason of the application of the S Factor mechanism – "in the previous regulatory control period". There is no amount of revenue to be carried forward as a result of applying the S Factor Scheme in the 2006–2010 regulatory period.
> 17. Presently there seems to be no justification given by the AER in the draft decision or elsewhere which would support its entitlement to make such adjustments to the building block approach. The AER has just adopted a method advanced in part by Citipower and others.
> 18. At this stage, in my opinion it is strongly arguable that the AER lacks the power to include an S Factor adjustment in the building block approach to close-out the ESCV's S Factor Scheme. The requirement of clause 6.12.3(c) of the NER is unlikely to authorise an approach set out in the Framework and Approach paper where that approach is contrary to the NER.
> 19. UED may also wish to argue that the S Factor Scheme is not a "control mechanism" and moreover, that the Scheme does not give rise to revenue increments or decrements, as distinct from higher or lower average percentage increases in the tariff basket formula.

218 In the final decision, the AER did not accept UED's revised regulatory proposal. Instead, it included in the building blocks for the regulatory period 2011–2015, in total, an amount of –$32.8 m (in real 2010 dollars) in respect of the close out of the ESCV S Factor Scheme. It included a lesser but still significant figure in respect of SP AusNet.

219 In making that decision, the AER relied on the methodology set out in its draft decision, subject to using an average of 2005–2010 performance as a basis for estimating performance in 2011 onwards.

220 In the final decision, the AER introduced its own service target performance incentive scheme (**STPIS**) for the DNSPs for the 2011–2015 regulatory control period. The AER stated that the STPIS provided financial incentives for DNSPs to maintain an improved service performance. In its final decision, the AER recognised that it was obliged to introduce an STPIS by cl 6.6.2(a) of the NER.

221 At pp 695–717 of the final decision, the AER dealt with (*inter alia*) the close out of the ESCV S Factor Scheme. At pp 696–697, the AER said:

> The ESCV S Factor Scheme will cease to operate at the end of the 2006–2010 regulatory period and will be replaced by the STPIS. The design and construction of the ESCV S Factor Scheme is such that the accrued financial outcomes of actual service performance in a particular year are lagged by two years and then have a continuing effect for six years. Hence, the financial impact on a DNSP resulting from the ESCV S Factor Scheme, for its actual performance in the 2010 calendar year, would not be fully realised until 2018. In ceasing the ESCV S Factor Scheme from operating (closing it out) consideration needs to be given to the effects of both the two year lag and the continuing effects of the ESCV S Factor Scheme.
>
> The AER considers it appropriate to apply a close out methodology that gives effect to the intended benefits, or penalties, of the ESCV S Factor Scheme. This ensures that if a DNSP has accrued a financial benefit, due to improved performance in the 2006–2010 regulatory period, then the DNSP is entitled to receive the benefit as per the construction of the scheme. Conversely, where a DNSP has accrued a financial penalty, due to reduced supply reliability in the 2006–2010 regulatory period, then customers are entitled to have this reflected in lower prices, as was intended under the ESCV S Factor Scheme. This approach would also give effect to the expected outcomes that the Victorian DNSPs could have reasonably expected at the time they made operational and investment decisions during the 2006–2010 regulatory period. In adopting this approach, the AER also considers that it is providing the Victorian DNSPs regulatory certainty for the investment and operational decisions made over the 2006–2010 regulatory period.
>
> Therefore, the AER considers that closing out the ESCV S Factor Scheme, by replicating the intended benefits or penalties of the ESCV S Factor Scheme, is consistent with the NEO. That is, it promotes efficient investment in, and efficient operation and use of, electricity services in the long term interests of consumers, by promoting regulatory certainty. In considering the most appropriate way to close out the scheme, the AER has also taken into account the revenue and pricing principles, specifically subsection (3) which states that a network service provider should be provided with effective incentives to promote economic efficiency.
>
> As the ESCV applied its S Factor Scheme to all Victorian DNSPs in a consistent manner, the AER considers it appropriate to apply a consistent methodology to close out the Scheme for all Victorian DNSPs.

222 At p 702 of the final decision, the AER said that it proposed to apply the benefits and penalties “accrued” in the 2006–2010 regulatory period under the ESCV S Factor Scheme as a building block element in the calculation of allowed revenue for the 2011–2015 regulatory control period. It went on to say that, following feedback on the methodology specified in its draft decision, it had changed its methodology for estimating the 2011 and ongoing performance by using an average of 2005–2010 service performance.

223 The AER noted that UED had submitted that the scheme should simply not proceed from 31 December 2010 but commented that UED’s proposal was inconsistent with the original design principles of the ESCV S Factor Scheme and did not provide regulatory certainty. It also criticised UED’s proposal for being inconsistent with the NEO.

224 The AER also said that, using an estimate of future performance, based on actual historical performance, represented a reasonable and necessary inclusion in the close out methodology (at p 858). It also said that using the average of 2005–2010 performance as an estimate of ongoing performance closely replicated the intended outcomes of the ESCV S Factor Scheme (at p 861).

225 In accordance with its stated objectives, the AER applied all the calculations of the ESCV S Factor Scheme set out in s 2.3 of the last ESCV price determination for all of the years from 2011 to 2018 inclusive and incorporated those financial outcomes into the building blocks in respect of the regulatory period 2011–2015.

A Brief Summary of the AER's Position before the Tribunal

226 In order to meet the contentions advanced on behalf of UED and SP AusNet to the effect that the AER did not have power under the NEL or the NER to adopt and implement the close out methodology in respect of the ESCV S Factor Scheme which it adopted in its final decision, the AER relied upon cl 6.4.3(a)(6) and cl 6.4.3(b)(6) as the source of power. The difference of opinion between the two camps in respect of the ESCV S Factor Scheme, in the end, came down to an issue of interpretation directed to those particular clauses in the NER. The AER also relied upon s 27 and s 28(2) in the *Interpretation of Legislation Act 1984* (Vic) as providing the necessary power.

227 In addition, the AER made detailed submissions supporting its methodology, on the assumption that it had the necessary power to close out the ESCV S Factor Scheme. This methodology was criticised by UED and SP AusNet, not so much because it is unreasonable, but rather upon the basis that it did not truly constitute a closing out of that scheme by replicating its consequences but rather amounted to a fresh mechanism for the imposition of incentives and disincentives upon the DNSPs.

228 The AER also submitted that, if the Tribunal is of the view that it lacked power to close out the ESCV S Factor Scheme, either at all or in the way that it did, the Tribunal should state that fact and publish its reasons for so doing but not go on to grant any relief at this point in time as a result of coming to that conclusion. This position was generally supported by the DNSPs, especially those which did not attack the decision (JEN, CitiPower and Powercor). The AER and other DNSPs wished to retain the right to argue, in due course,

that, notwithstanding that the Tribunal may have expressed a conclusion that the AER lacked power to make its ESCV S Factor Scheme close out decision, that conclusion should not affect the position of those DNSPs whose applications for review did not raise such a contention.

The Contentions of UED and SP AusNet

229 SP AusNet adopted UED's submissions in respect of the ESCV S Factor Scheme.

230 UED's fundamental proposition was that the AER had no power to implement the ESCV S Factor Scheme close out which it included in the final decision. Acting to close out this scheme, when it had no power to do so, was an incorrect exercise of discretion or an unreasonable decision in all of the circumstances or, in the judicial review proceeding brought by UED, an error of law or jurisdictional error.

231 UED submitted as follows:

(a) The ESCV S Factor Scheme expired according to its terms on 31 December 2010. Had State-based regulation of the DNSPs continued beyond that date, then perhaps the legacy of that scheme would have needed to have been addressed by the ESCV in respect of the succeeding regulatory period (2011–2015). But, State-based regulation also ceased on 31 December 2010. The administration of the last ESCV price determination had been transferred to the AER by the 2007 amendments to the NEVA.

(b) Upon the assumption that the AER had power to close out the ESCV S Factor Scheme, the methodology adopted by the AER did not constitute a close out of that scheme. Rather, the AER has created a simulation of it. This simulated model is a new and separate model from the ESCV S Factor Scheme.

(c) The ESCV S Factor Scheme affects, and is only capable of affecting, prices or the average price in a year, when the scheme is in operation. It is backward looking, not forward looking. It does not explicitly carry forward any payments from one year to the next. It is simply not at all forward looking whereas the fundamental concept underpinning the building blocks approach is that it looks forward.

(d) Neither the terms of cl 6.4.3(a)(6) nor the terms or cl 6.4.3(b)(6) authorise the decision made by the AER in respect of the close out of the ESCV S Factor Scheme.

(e) Clause 6.4.3(a)(5) and cl 6.4.3(a)(6) are in the following terms:

> **6.4.3 Building block approach**
>
> **(a) 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:
>
> …
>
> (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
>
> …

(f) Clause 6.4.3(b)(5) and cl 6.4.3(b)(6) provide as follows:

> **(b) Details of the building blocks**
>
> For the purposes of paragraph (a):
>
> …
>
> (5) 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; and
>
> (6) the other revenue increments or decrements referred to in paragraph (a)(6) arc 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*; and
>
> …

(g) Subclauses (5) and (6) of cl 6.4.3(b) explain in more detail the meaning of the corresponding clauses in cl 6.4.3(a).

(h) The building blocks referred to comprise revenue increments and decrements for each regulatory year. In subcl (5) of cl 6.4.3(a), those increments or decrements (if any) must arise from the application of various specific schemes referred to in the subclause. The ESCV S Factor Scheme is not expressly referred to in cl 6.4.3(a)(5) and is not within the definition of any of the specific schemes which are referred to in that subclause. Each of those schemes is defined in Ch 10, Glossary, of the NER. Each is a scheme which is published by the AER under the NER. When regard is had to the terms of subcl (5) of cl 6.4.3(b), it is readily apparent that the specific schemes referred to are schemes which the AER is obliged to promulgate under the NER (see cll 6.5.8, 6.6.2 and 6.6.3).

(i) Subclause (6) of cl 6.4.3(a) speaks of *"… other …"* revenue increments or decrements (if any) for that year *"… arising from the application of a control mechanism in the previous* regulatory control period*"*. According to subcl (6) of cl 6.4.3(b), those increments or decrements 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****.*

(j) The expression *annual revenue requirement* is defined in Ch 10, Glossary, as:

> An amount representing revenue for a [DNSP] for each *regulatory year* of a *regulatory control period*, calculated in accordance with Part C of Chapter 6.

It does not mean actual or realised revenues.

(k) *Regulatory year* is defined in Ch 10 as follows:

> Each consecutive period of 12 calendar months in a *regulatory control period*, the first such 12 month period commencing at the beginning of the *regulatory control period* and the final 12 month period ending at the end of the *regulatory control period*. For *AEMO*, each *financial year* is a *regulatory year*.

(l) *Regulatory control period* is defined in Ch 10 as follows:

> …
> (b) In respect of a *Distribution Network Service Provider*, a period of not less than 5 *regulatory years* for which the provider is subject to a control mechanism imposed by a distribution determination.

(m) *Distribution determination* is not defined in Ch 10 but is defined in s 2 of the NEL. It means a determination made by the AER under the NER which regulates any one or more of the specified matters. We have set out the definition in full at [28] above. The definition applies to the expression when used in the NEL. It also applies to the expression when used in the NER except insofar as the contrary intention appears in the NER (see cl 13 of Sch 2 to the NEL). No such contrary intention is apparent in the NER.

(n) Whether or not the ESCV S Factor Scheme is a control mechanism within the meaning of subcl (6) of cl 6.4.3(a) and subcl (6) of cl 6.4.3(b) of the NER, the last ESCV price determination is not a *distribution determination* for the purposes of cl 6.4.3(a)(6) and cl 6.4.3(b)(6) because it was not made by the AER. In any event, it is not a control mechanism within the meaning of that expression in cl 6.4.3(a)(6) and cl 6.4.3(b)(6). One of the reasons that it is not such a control mechanism is because it is not prospective but is backward-looking.

(o) The NER has been drafted upon the basis that the only increments or decrements which are to be carried forward from one *regulatory control period* to another are those which arise from the application of a control mechanism in a regulatory period which was the subject of regulation by the AER. The ESCV S Factor Scheme is not such a control mechanism.

(p) In any event, by virtue of s 16(4)(b) of the NEVA, a Victorian distribution pricing determination is not a distribution determination for the purposes of the NEVA or the NER. Section 3 of the NEVA defines *"a Victorian pricing determination"* as (*inter alia*) the last ESCV price determination (see sub-par (a) of the definition). This provision makes crystal clear the proposition that the phrase *"previous* ***regulatory control period****"* when used in cl 6.4.3(a)(6) and cl 6.4.3(b)(6) cannot be a reference to the regulatory period governed by the last ESCV price determination. The expression is confined to previous distribution determinations made by the AER itself.

(q) Clause 6.4.3(a)(5) and cl 6.4.3(b)(5) are not now relied upon as supporting the decision under challenge. There are no other provisions in the NEL, the NER or in any other legislation or instrument that authorise the decision which the AER has made in respect of closing out the ESCV S Factor Scheme.

232 UED also submitted that, notwithstanding that, in respect of some matters, transitional regulation was provided in the NER, no transitional provisions were put in place in respect of the ESCV S Factor Scheme. For example, cl 9.29.5(b)(2) of the NER required the AER to carry forward impacts of the South Australian Service Incentive Scheme established by the Essential Services Commission of South Australia as part of its electricity distribution price

determination which operated in South Australia during the period July 2005 – June 2010. Had the draftsman of the NER and the NEL intended that the impacts of the ESCV S Factor Scheme would be carried forward into the current regulatory control period, he or she could have and should have provided for that to occur by means of appropriate transitional provisions.

233 Senior Counsel for UED spent some time explaining to the Tribunal that, even if the AER is found to have had the necessary power to close out the ESCV S Factor Scheme, the methodology which was adopted did not replicate that scheme but rather implemented a fresh and different scheme. There was considerable force in these submissions.

234 For reasons which we will shortly explain, it is not necessary for us to traverse these submissions in any detail.

The AER's Position

235 The AER explained its position in detail in a Written Submission revised 31 March 2011 as further developed by submissions made orally to the Tribunal.

236 The AER submitted that:

(a) The Tribunal should adopt a purposive construction of the relevant rules in the NER.

(b) The AER relied on cl 6.4.3(a)(6) as the sole source of its power to close out the ESCV S Factor Scheme .

(c) The expression *"previous* ***regulatory control period****"* when used in cl 6.4.3(a)(6) and cl 6.4.3(b)(6) should be interpreted as covering a regulatory period under State jurisdictional arrangements. For this reason, the last ESCV price determination should be regarded as a distribution determination for the purposes of those subclauses.

(d) The relevant subclauses should be construed broadly. The contents of those subclauses, juxtaposed as they are in cl 6.4.3, indicate an intention on the part of the legislative draftsman that:

(i) Clause 6.4.3(a)(5) provides for increments or decrements to be applied to the DNSP's annual revenue requirement for a particular regulatory year arising from the application of the specific incentive schemes referred to in that provision; and

(ii) Clause 6.4.3(a)(6) is to provide for increments or decrements to be applied to the DNSP's annual revenue requirement for that year arising from the application of any other control mechanisms, including incentive schemes, which have an effect carrying over from a previous period.

(e) There were good reasons why the draftsman of the NER would have wanted to carry forward into the current regulatory control period the impacts of the ESCV S Factor Scheme. First and foremost among those reasons was the desirability of avoiding windfall gains and losses among the DNSPs by maintaining a consistent incentive scheme which applied rewards and penalties (depending upon performance) in the long term interests of consumers of electricity.

(f) By the combined operation of s 27 of the *Interpretation of Legislation Act 1984* (Vic) and s 23 of the NEVA, the AER had an implied power to amend the ESCV S Factor Scheme. The substance of its decision was no more than an amendment of that scheme. Accordingly, the two statutory provisions mentioned authorised the making of the decision under challenge.

237 The AER also submitted that SP AusNet was prevented from piggy-backing UED in respect of UED's main argument (that the AER lacked power to do that which it did) because SP AusNet had never argued this point during the regulatory process and has not been given leave to do so now.

238 Despite SP AusNet's attempts to persuade the Tribunal that it did in fact argue this point before the AER, we are of the view that it did not do so. It seems to us, therefore, that it cannot now raise the point because it is prevented from doing so by reason of s 71O(2). However, it may, nonetheless, be open for SP AusNet to rely upon any decision which the Tribunal makes in respect of the arguments advanced by UED. There may be several reasons for this. If UED is successful on this point, we shall defer further consideration of the implications of such a decision on SP AusNet and the other DNSPs.

The Minister's Submissions

239 The Minister agreed with the AER's approach in respect of the ESCV S Factor Scheme.

240 The Minister submitted that:

(a) The reward or penalty thrown up by the ESCV S Factor Scheme was applied through the price control formula by adjusting the price cap and thereby increased (if rewarded) or decreased (if penalised) the DNSP's revenue.

(b) The design of the scheme was based upon the idea that the rewards and penalties would be applied across regulatory control periods. The objectives of the scheme would not be met if the rewards and penalties from the scheme are not carried over from one regulatory period to the next regulatory period.

(c) The transition of the scheme into the 2011–2015 regulatory control period was provided for under cl 6.4.3(a)(6) and cl 6.4.3(b)(6) and the STPIS.

(d) For the purposes of cl 6.4.3(a)(6) and cl 6.4.3(b)(6), the relevant control mechanism is tariff basket price control (cl 6.2.5(b)(4)). Prices are set with a view to bringing in sufficient revenue to cover the costs of providing the relevant services in an efficient and cost effective manner. The ESCV S Factor Scheme complements the efficiency carry over mechanisms embodied in the last ESCV price determination.

(e) The ESCV S Factor mechanism is a control mechanism for the purposes of cl 6.4.3(a)(6) and cl 6.4.3(b)(6) of the NER.

(f) The final decision incorporates a satisfactory methodology for closing out the ESCV S Factor Scheme.

(g) There are other clauses in the NER which suggest that the expression "*distribution determination*" when used in cl 6.4.3(a)(6) and cl 6.4.3(b)(6) is not confined to determinations made by the AER.

(h) If the approach of the AER as reflected in the ESCV S Factor Scheme close out methodology in the final decision is not adopted, there is a serious potential for windfall gains and losses to be experienced by the DNSPs during the current regulatory control period 2011–2015 while the incentive scheme transitions to the STPIS.

Decision

241 The essence of the issue confronting the Tribunal in respect of the AER's decision to implement a methodology to close out the ESCV S Factor Scheme is one of interpretation. The critical question is whether cl 6.4.3(a)(6) and cl 6.4.3(b)(6) of the NER, upon their true interpretation, permit the carrying forward into the current regulatory control period 2011–2015 of the ESCV S Factor Scheme being a scheme which was in operation only in respect of the State-based last ESCV price determination up to 31 December 2010. That question is answered favourably to the position of the AER and the Minister if the subclauses to which we have referred contemplate the carrying over of such a State-based regulatory regime.

242 In our view, however, the subclauses referred to do not permit such a course. This is essentially for the reasons advanced by UED. The draftsman of the NER intended, in our view, to start with a clean slate in respect of incentive schemes as at 1 January 2011. This is no accident. Had the draftsman wished to authorise that which the AER has in fact done in the present case, he or she could have done so by prescribing appropriate transitional provisions, as was done in the case of South Australia. This was not done. Instead, the AER was required to propound its own incentive scheme (STPIS) and to do so in respect of the first regulatory control period for which it was charged with the responsibility of making the relevant determination.

243 At [56]–[61] above, we have discussed the governing principles and provisions for the interpretation of the NEL and the NER. Applying those principles to the present problem, it seems to us that:

(a) The extrinsic material to which our attention was drawn does not assist, one way or the other, in the interpretation of cl 6.4.3(a)(6) and cl 6.4.3(b)(6).

(b) Despite the fact that cl 7 requires that the interpretation that will best achieve the purpose or object of the NEL is to be preferred to any other interpretation, that notion is not a mandate for a wholesale redrafting of the relevant provision.

244 The language deployed in the relevant subclauses is clear enough. Interpreting the language according to its ordinary meaning and in accordance with the relevant definitions contained in the Glossary for the NER and in s 2 of the NEL does not produce absurd results. It may produce results with which the AER and the Minister disagree – disagreement which

may, in the circumstances of the present case, even be supportable by reasoned argument. However, in our view, this is quite beside the point. We are not authorised to rewrite the relevant subclauses.

245 Even if the *Interpretation of Legislation Act 1984* (Vic) applies to the interpretation of the NER (and we think that it does not), we do not accept that s 27 of that Act is of any assistance to the AER in the circumstances of the present case. As UED has pointed out in its Reply Submissions, the power to amend the ESCV S Factor Scheme is constrained very substantially by the terms of cl 2.3.9(i) of the last ESCV price determination. Neither the ESCV nor the AER had a general right to vary the implementation mechanisms. The closeout methodology is not, in any event, an amendment of the ESCV S Factor Scheme. It is an engrafted methodology designed to mimic the effects of that scheme while, at the same time, bringing it to an end.

246 Similarly, we do not think that s 28(2) of the *Interpretation of Legislation Act 1984* (Vic) is of any assistance to the AER and the Minister. Subsection (2)(e) and subs (2)(f) of s 28 are relied upon in support of the proposition that both the rewards and penalties that would have been imposed in the 2011–2015 regulatory control period had the scheme continued into that period should, in effect, be preserved. But, the scheme expired on 31 December 2010. At that time, no price adjustments in respect of the 2011-2015 regulatory control period had been made or had accrued. The most that can be said is that the financial impacts of the scheme were notionally or contingently in place, subject to the scheme continuing beyond 31 December 2010 (which, of course, did not happen). Section 28(2) does not assist.

Conclusion

247 For these reasons, the Tribunal is of the opinion that the AER did not have power to include within its final decision the methodology and consequential decision directed to the closing out of the ESCV S Factor Scheme. The year-by-year penalty sought to be imposed on UED by the AER's adoption of its close-out methodology cannot be imposed on UED. We propose to deal with UED's position now. The consequences of this conclusion on other DNSPs are reserved for further consideration in light of further submissions which we will invite the parties to make.

ISSUE 4—ESTABLISHMENT OF THE REGULATORY ASSET BASE (CAPITALISED RELATED PARTY MARGINS)

Introduction

248 In the final decision, in conformity with a constituent decision made during the regulatory process, the AER permitted the inclusion of related party profit margins (**related party margins**) in all of the DNSPs' capital expenditure actually incurred in the 2006–2010 regulatory period in establishing the opening RAB for the *regulatory control period* 2011–2015 as at 1 January 2011. The AER concluded that it was bound to include the related party margins because cl 6.5.1 of the NER and Sch 6.2 to the NER required that it do so.

249 Unsurprisingly, all of the DNSPs were content with the AER's decision on this point. The Minister, however, disagreed with the AER's decision and was given leave to intervene in the present review in order to challenge that decision.

250 The Minister argued before the Tribunal that the AER misunderstood and thus misapplied the requirements of cl 6.5.1 of the NER and Sch 6.2 to the NER and therefore incorrectly exercised its discretion, having regard to all the circumstances, or made a decision which was unreasonable, having regard to all the circumstances.

The Relevant Provisions of the NER

251 One of the constituent decisions which the AER was obliged to make was a decision establishing the RAB as at the commencement of the *regulatory control period* (viz as at 1 January 2011) "… *in accordance with clause 6.5.1 and schedule 6.2*" of the NER (cl 6.12.1(6) of the NER).

252 Clause 6.4.3(a)(1) of the NER provides that one of the building blocks which must be used to derive a DNSP's *annual revenue requirement* is indexation of the RAB.

253 Clause 6.4.3(b)(1)(i) provides that, for the purposes of cl 6.4.3(a)(1) for indexation of the RAB, the RAB is calculated in accordance with cl 6.5.1 and Sch 6.2 of the NER.

254 Clause 6.5.1 of the NER provides:

6.5 Matters relevant to the making of building block determinations

6.5.1 Regulatory asset base

Nature of regulatory asset base

(a) The regulatory asset base for a *distribution system* owned, controlled or operated by a *Distribution Network Service Provider* is the value of those assets that are used by the provider to provide standard control services, but only to the extent that they are used to provide such services.

Preparation, publication and amendment of model for rolling forward regulatory asset base

(b) The *AER* must, in accordance with the *distribution consultation procedures*, develop and *publish* a model for the roll forward of the regulatory asset base for *distribution systems*, referred to as the *roll forward model*.

(c) The *AER* may, from time to time and in accordance with the *distribution consultation procedures*, amend or replace the *roll forward model.*

(d) The *AER* must develop and *publish* the first *roll forward model* within 6 months after the commencement of this clause, and there must be such a model available at all times after that date.

Contents of roll forward model

(e) The *roll forward model* must set out the method for determining the roll forward of the regulatory asset base for *distribution systems*:

(1) from the immediately preceding *regulatory control period* to the beginning of the first year of the subsequent *regulatory control period*, so as to establish the value of the regulatory asset base as at the beginning of the first *regulatory year* of that subsequent *regulatory control period;* and

(2) from one *regulatory year* in a *regulatory control period* to a subsequent *regulatory year* in that same *regulatory control period* so as to establish the value of the regulatory asset base as at the beginning of that subsequent *regulatory year*;

under which:

(3) the roll forward of the regulatory asset base from the immediately preceding *regulatory control period* to the beginning of the first *regulatory year* of a subsequent *regulatory control period* entails the value of the first mentioned regulatory asset base being adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism (or control mechanisms) for *standard control services* during the preceding *regulatory control period*.

Other provisions relating to regulatory asset base

(f) Other provisions relating to regulatory asset bases are set out in schedule 6.2.

255 Clause 6.5.1 contains some of the relevant provisions in respect of the RAB. Clause 6.5.1(f) directs attention to Sch 6.2 to the NER.

256 Clause S6.2.1 (which is found in Sch 6.2 to the NER) governs the establishment of the value of the RAB for a *distribution system* as at the beginning of a *regulatory control period* on the roll forward of the RAB to that *regulatory control period* from the previous *regulatory control period* (cl S6.2.1(a)(1)) and also applies to the establishment of the RAB for a *distribution system* as at the beginning of a *regulatory control period* where the *distribution system* was not immediately before that time the subject of a *building block determination* (cl S6.2.1(a)(2)).

257 In the present review, it is cl S6.2.1(a)(2) which engages Sch 6.2 to the NER insofar as the establishment of the opening RAB for the DNSPs as at 1 January 2011 is concerned.

258 Clause S6.2.1(b) provides that the values to be used for completing the RFM must be established in accordance with cl S6.2.1, cl S6.2.2 and cl S6.2.3.

259 Clause S6.2.1(c)(1) provides that, in the case of the *distribution systems* owned, controlled or operated by (*inter alia*) the DNSPs as at 1 January 2008 (which covers all of the *distribution systems* currently owned by the DNSPs), the value of the RAB for each *distribution system* as at 1 January 2011 must be determined by rolling forward the RAB for that *distribution system* as set out in the table appearing immediately below the text of cl S6.2.1(c)(1) in accordance with Sch 6.2.

260 The tabular schedule forming part of cl S6.2.1(c)(1) of the NER laid down specific sums of money as the value of the RAB for each of the DNSPs expressed as at 1 January 2006 in July 2004 dollars.

261 Immediately under that schedule, cl S6.2.1(c)(2) and cl S6.2.1(c)(3) appear. Those subclauses are in the following terms:

> (2) The values in the table above are to be adjusted for the difference between:
>
> (i) any estimated capital expenditure that is included in those values for any part of a previous *regulatory control period*; and
>
> (ii) the actual capital expenditure for that part of the previous *regulatory control period.*

This adjustment must also remove any benefit or penalty associated with any difference between the estimated and actual capital expenditure.

(3) When rolling forward a regulatory asset base under subparagraph (1), the *AER* must take into account the derivation of the values in the above table from past regulatory decisions and the consequent fact that they relate only to the regulatory asset base identified in those decisions.

262 Clause S6.2.1(d) deals with *distribution systems* not covered by cl S6.2.1(c). For this reason, cl S6.2.1(d) is not presently relevant.

263 Clause S6.2.1(e) and cl S6.2.1(f) of the NER are in the following terms:

(e) Method of adjustment of value of regulatory asset base

Except as otherwise provided in paragraph (c) or (d), the value of the regulatory asset base for a *distribution system* as at the beginning of the first *regulatory year* of a *regulatory control period* must be calculated by adjusting the value (the **previous value**) of the regulatory asset base for that *distribution syste*m as at the beginning of the first *regulatory year* of the immediately preceding *regulatory control period* (the p**revious control period**) as follows:

(1) The previous value of the regulatory asset base must be increased by tine amount of all capital expenditure incurred during the previous control period.

(2) The previous value of the regulatory asset base must be increased by the amount of the estimated capital expenditure approved by the *AER* for any part of the previous control period for which actual capital expenditure is not available.

(3) The previous value of the regulatory asset base must be adjusted for the difference between:

(i) the estimated capital expenditure for any part of a previous *regulatory control period* where that estimated capital expenditure has been included in that value; and

(ii) the actual capital expenditure for that part of the previous *regulatory control period.*

This adjustment must also remove any benefit or penalty associated with any difference between the estimated and actual capital expenditure.

(4) The previous value of the regulatory asset base must only be increased by actual or estimated capital expenditure to the extent that all such capital expenditure is properly allocated to the provision of *standard control services* in accordance with the *Cost Allocation Method* for the relevant *Distribution Network Service Provider*.

(5) The previous value of the regulatory asset base must be reduced by the amount of depreciation of the regulatory asset base during the previous *regulatory control period* calculated in accordance with the distribution determination for that period.

(6) The previous value of the regulatory asset base must be reduced by the disposal value of any asset where that asset has been disposed of during the previous *regulatory control period*.

(7) The previous value of the regulatory asset base must be reduced by the value of an asset where *the asset was previously used to provide* standard control services (or their equivalent under the previous regulatory system) but, as a result of a change to the classification of a particular service under Part B, is not to be used for that purpose for the relevant *regulatory control period*.

(8) The previous value of the regulatory asset base may be increased by the value of an asset to which this subparagraph applies to the extent that:

(i) the *AER* considers the asset to be reasonably required to achieve one or more of the *capital expenditure objective*s; and

(ii) the value of the asset has not been otherwise recovered.

This subparagraph applies to an asset that:

(i) was not used to provide *standard control services* (or their equivalent under the previous regulatory system) in the previous *regulatory control period* but, as a result of a change to the classification of a particular service under Part B, is to be used for that purpose for the relevant *regulatory control period*; or

(ii) was never previously used to provide *standard control services* (or their equivalent under the previous regulatory system) but is to be used for that purpose for the relevant *regulatory control perio*d.

(f) An increase or reduction in the value of the regulatory asset base under subparagraph (7) or (8) of paragraph (c) is to be based on the portion of the value of the asset properly allocated, or formerly properly allocated, to *standard control services* in accordance with the principles and policies set out in the *Cost Allocation Method* for the relevant *Distribution Network Service Provider*. The value of the relevant asset is taken to be its value as shown in independently audited and published accounts.

264 The critical clause for present purposes is cl S6.2.1(e)(1).

265 It is clear from the terms of the above provisions that, subject to giving effect to cl S6.2.1(c)(3), the RAB for each of the *distribution systems* operated by the DNSPs was fixed as at 1 January 2006 (the beginning of the last regulatory period in Victoria which, for most of that period, was regulated by the ESCV) at the specific sums specified in the tabular Schedule to cl S6.2.1(c)(1).

266 The amount by which the RAB of each of the DNSPs was to be increased in accordance with cl S6.2.1(e)(1) is the amount of all capital expenditure incurred during the regulatory period 2006–2010.

The Present Question

267 The present question concerns the correct interpretation of cl S6.2.1(e)(1). As Senior Counsel for the Minister conceded, this is a pure question of statutory interpretation.

268 The AER decided that it was bound to include in the RAB for each of the DNSPs all capital expenditure actually incurred by that DNSP in the 2006–2010 *regulatory control period*.

269 The Minister submitted that, upon the true interpretation of cl S6.2.1(e)(1) of the NER, the AER was permitted to include in the RAB only those classes or categories of capex which, pursuant to the last ESCV price determination, had been permitted by the ESCV to be incurred. He also submitted that those related party margins that the ESCV was able to identify as effectively increasing the cost to the DNSP of capital expenditure above the cost of providing the capital items should be disallowed.

270 The contentions made by the Minister necessarily require the AER to conduct some kind of *ex post* efficiency review in respect of the actual capex undertaken by each of the DNSPs before finally determining the amount that is to be included in the RAB as at the commencement of the new *regulatory control period*.

The AER's Draft and Final Decisions

271 In the initial regulatory proposals submitted by the DNSPs, each DNSP informed the AER that it had incurred related party margins during the 2006–2010 regulatory period.

272 The AER accepted that the related party margins were of a capital nature.

273 In its draft decision, the AER included the DNSPs' related party margins as part of establishing and calculating the value of each DNSP's opening RAB for the 2011–2015 *regulatory control period* in accordance with cl S6.2.1(e)(1) of the NER. The quantum of

these related party margins was set out in the draft decision at Table 9.4 (which is at p 450 of the draft decision).

274 On 18 August 2010, the Minister made a written submission to the AER in which he contended that the AER should exclude altogether the DNSPs' related party margins in establishing the values of the DNSPs' opening RABs upon the basis that the AER had misinterpreted cl S6.2.1(e)(1) of the NER.

275 In his submission to the AER, the Minister argued that the only assets which could properly be included in the RAB were those which were used by the DNSPs to provide *standard control services* subject to the further qualification that such assets may only be included to the extent that they are used to provide such services. The Minister contended that, to the extent that related party margins were inflated above the true cost of providing the capital items in respect of which those margins were paid, the assets acquired in this fashion did not meet the requirements of cl 6.5.1(a) of the NER.

276 The AER did not agree with the Minister's submission that it had misinterpreted cl S6.2.1(e)(1) nor did it agree that it had any discretion to review and perhaps exclude all or part of the DNSPs' related party margins.

277 At pp 457–459 of the final decision, the AER expressed its final views on the matter. At p 457, the AER said:

> … the AER's task is limited to determining whether the amounts proposed to be included in the RAB can be said to be "capital expenditure incurred" for the purposes of clause S6.2.1(e)(1).

278 At p 458, after stating that it had carefully examined the nature of the related party margins, the AER said:

> The evidence does not suggest that the margins paid by the Victorian DNSPs are so excessive as to have no relationship with the distribution and the provision of standard control services through the distribution system. Further there is also nothing to suggest that the margins paid bear no relationship to the activity of acquiring or creating capital items. Nor is there any suggestion that any of these margins serve purposes other than for the payment of capital.

279 At pp 458–459, the AER expressed its conclusions as follows:

> In summary, the AER considers that its task in the RAB roll forward is limited to determining whether the amounts proposed to be included in the RAB are 'capital expenditure incurred'. As discussed above, having reviewed the evidence before it, the AER does not consider that the margins paid by the DNSPs to their related parties have no relationship to the activity of acquiring or creating capital items or are not of a capital nature.
>
> However, the question as to whether related party margins meet the requirement of capital expenditure incurred is separate to the issue of whether the related party margins included within the Victorian DNSPs proposed forecast capex are efficient or prudent and ultimately, whether the AER is dissatisfied that they reasonably reflect the capex criteria. This is discussed further in chapter 6.
>
> The issue of symmetry between capex and opex incentives (noted in the case of capitalisation policy changes) may be addressed by extending the AER's EBSS to capex as provided for under the NER. The AER considers, however, that the capitalisation of related party margins potentially gives rise to more fundamental issues relating to the requirements of cl S6.2.1(e)(1), which may be addressed by a rule change (including to the equivalent provisions in chapter 6A).
>
> **9.5.4.4 AER Conclusion**
>
> The AER has not made adjustments to the Victorian DNSPs' roll forward calculations with respect to related party margins.

The Minister's Contentions

280 The Minister accepted that cl S6.2.1(e)(1) appears to provide the AER with, at best, a limited and, at worst, no, discretion to scrutinise the related party margin expenditure of each DNSP at the time of the roll-in of capital expenditure incurred in the previous regulatory period into the RAB for the new regulatory period. Senior Counsel for the Minister submitted that such a literal interpretation of cl S6.2.1(e)(1) leads to *"… the creation of perverse and unintended financial incentives on DNSPs"*.

281 Such an interpretation would, so it was submitted, provide an inducement for DNSPs to contract with related parties at inflated margins. DNSPs could do so in the confident expectation that full contract value will inevitably be rolled into the RAB at the commencement of the next regulatory period with limited or no scrutiny by the AER. Such an outcome has the potential to allow too great a proportion of the benefits of any efficiency gains to be retained within the particular corporate group of which an individual DNSP is a member. Distribution tariffs will be higher than they otherwise would have been with no increase in service. This outcome is not in the long-term interests of consumers of electricity.

282 In the last ESCV price determination, the ESCV excluded related party margins from the DNSPs' capex allowances. It should not now be possible to introduce into the RAB that disallowed expenditure.

283 The Minister said that his submissions were consistent with the NEO and the RPP. He submitted that the interpretation of cl S6.2.1(e)(1) of the NER for which he contended accorded both with the policy and intent behind the regulatory provisions in respect of the RAB.

284 The Minister submitted that, if the Tribunal accepted his contentions, the issue will need to be remitted to the AER so that it can conduct an inquiry as to which of the related party margins should be disallowed in conformity with the interpretation of the relevant provisions advocated by the Minister.

285 The Minister accepted that, if the AER's interpretation of cl S6.2.1(e)(1) of the NER is the correct interpretation of that clause, then the AER's assessment of the actual expenditure incurred by the DNSPs in the regulatory period 2006–2010 was reasonable in all the circumstances. The Minister accepted that the entire success of this ground of review raised by him depended upon the Tribunal deciding that the interpretation of cl S6.2.1(e)(1) for which he contended was the correct interpretation.

The DNSPs' Contentions

286 JEN, UED, CitiPower and Powercor all actively opposed the Minister. SP AusNet adopted the submissions of the other DNSPs.

287 The DNSPs submitted that:

(a) Such adjustments as had been made by the ESCV to the DNSPs' capital expenditure allowances (and, in the case of some DNSPs, there were none) were immaterial.

(b) Clause S6.2.1(e)(1) means what it says. There is no reason to rewrite it. It does not produce a result that is manifestly absurd or unreasonable.

(c) The extrinsic material to which the Tribunal may legitimately have regard as an aid to interpretation of cl S6.2.1(e)(1) strongly supports the interpretation for which the AER and the DNSPs contended.

(d) The notion that the AER should conduct an *ex post* efficiency review in order to determine the quantum of allowable capex incurred in the prior period (here, in the period 2006–2010) had been explicitly rejected by the makers of the relevant rule.

(e) It was impossible to discern in the last ESCV price determination a principle along the lines of the principle which the Minister suggested should be carried forward into the present regulatory regime.

(f) The present question concerns the roll forward of the opening RAB for the new *regulatory control period*. It does not deal with the roll forward of the RAB within that *regulatory control period*. As to the latter, different considerations may well apply.

Decision

288 Clause 6.5.1 requires that only the value of assets that are used by the DNSPs to provide *standard control services* (to the extent that they are used to provide such services) are to be included in the RAB. In accordance with cl 6.5.1, the AER is to prepare and publish a RFM for the roll forward of the RAB. It must do so in accordance with Sch 6.2 to the NER.

289 In the case of the DNSPs, the starting point is the table which fixes, as at 1 January 2006, in July 2004 dollars the value of the RAB for each of the DNSPs. It is those values which are to be increased in accordance with cl S6.2.1(e)(1).

290 Given the specific terms of cl S6.2.1(c) and the details contained in the table which appears as part of cl 6.2.1(c)(1) of the NER, we think that the words *"… the previous control period …"* in cl S6.2.1(e)(1), when considered in the context of establishing the DNSPs' RAB as at 1 January 2011, clearly refer to the period 2006–2010 which was the period covered by the last ESCV price determination. If that phrase is not interpreted in that way, Sch 6.2 will be denied effect. This is manifestly absurd and unreasonable in all the circumstances.

291 In addition, the word *"incurred"*, when used in cl S6.2.1(e), means acquitted or actually spent.

292 In our view, cl S6.2.1(e)(1) requires that the RAB be increased by the amount of actual capital expenditure incurred during the previous control period which, for present

purposes, is the period 2006–2010. The only additional point to be made is that the expenditure must be of the kind described in cl 6.5.1(a).

293 The above interpretation is what the Minister has described as *"a literal construction"*. It is the construction arrived at by interpreting the words as they appear in the subclause, bearing in mind the context in which they appear and the purpose for which the establishment of the initial RAB under the new regulatory regime is to be undertaken.

294 The Minister's favoured interpretation involves a rewriting of cl S6.2.1(e)(1). The Minister conceded that additional words would have to be included in the clause if his interpretation is correct. In our view, there is no warrant for rewriting the clause in this way.

295 We have addressed the principles which govern the way in which the NEL and the NER are to be interpreted at [56]–[61] above. We will not repeat those principles in their entirety here. However, we will apply them to the interpretation of cl S6.2.1(e)(1).

296 It must also be remembered that the Tribunal may take account of *Law extrinsic material* and *Rule extrinsic material* (as defined in cl 8 of Sch 2 to the NEL) for all of the purposes specified in cl 8(2)(a) and (3) of the NEL. Those purposes include the purpose of confirming the interpretation conveyed by the ordinary meaning of the provision. Resort to extrinsic material is not limited to circumstances where there is ambiguity or obscurity in the text of the relevant provision or where the ordinary meaning of the words used in the relevant provision leads to a result that is manifestly absurd or unreasonable. The task of the Tribunal is to interpret the relevant provision, not to rewrite it.

297 In the present case, both the Minister and the DNSPs referred to extrinsic material in order to support their respective contentions.

298 The Minister pointed to cl S6A.2.1(f)(1) of the NER and to the draft and final determination in respect of that clause promulgated by the AEMC. The material to which the Minister referred did not assist his argument. If anything, it established the opposite of the interpretation for which he contended.

299 JEN submitted that the relevant extrinsic materials confirm that the intention of the draftsman of cl S6.2.1(e)(1) of the NER was for there to be no *ex post* review of capital expenditure at the opening of the new *regulatory control period* when capital expenditure incurred during the previous *regulatory period* is rolled into the RAB.

300 The rule proposal promulgated by the AEMC in respect of what became cl S6A.2.1(f)(1) of the NER was promulgated in February 2006. That rule proposal reflected an approach which involved the assessment by the AER of actual capital expenditure in order to be satisfied that it was both prudent and efficient. Only prudent and efficient capital expenditure would be permitted to be rolled into the RAB, according to that rule proposal.

301 The AEMC received many submissions which addressed the idea that there should be some kind of *ex post* review.

302 The AEMC carefully considered those submissions. As a result, it modified its proposal so as to remove the possibility of *ex post* reviews by the AER of capital expenditure before rolling actual capital expenditure into the RAB.

303 At p 76 of its draft rule determination, the AEMC said:

> In general the criticism of the proposed *ex post* prudency review was that it undermined the incentives of the *ex ante* cap and contributed to the investment uncertainty the remainder of the package sought to overcome. Submissions also raised the legitimate concern that *ex post* prudency reviews are, by their very nature, an intrusive form of regulation. An *ex post* review effectively requires the regulator to put itself in the position of a TNSP [transmission network service provider] at the time that they were undertaking a particular project to determine if the project was undertaken efficiently. Previously, this process has been the subject of controversy when it has been applied to network businesses.
>
> For these reasons, the Commission is sympathetic to submissions for the elimination of *ex post* reviews and has instead focussed more on improving *ex ante* incentives. For example, to the extent overspending occurs, this can be taken into account in the setting of the capital expenditure allowance for the following regulatory period. The Commission considers that the inclusion of depreciation into the capital expenditure incentive mechanism will partly offset the loss of regulatory discipline inherent in the removal of *ex post* reviews.

304 In its final rule determination, the AEMC maintained the modified position which it had reflected in its draft rule determination. It did so for essentially the same reasons as it stated in its draft rule determination.

305 It seems to us that the draft and final rule determinations of the AEMC confirm the literal interpretation of cl S6.2.1(e)(1) of the NER.

306 The ordinary literal construction is further confirmed by a 2007 response of the Standing Committee of Officials of the Ministerial Council on Energy (**SCO**) to stakeholder comments on the Exposure Draft of the National Electricity Rules for distribution revenue and pricing. Items 47 and 100 of that document note a proposal from stakeholders that an *ex post* review of capex should be allowed. The SCO response made clear that that proposal was not accepted. The SCO went on to state (at p 29):

> At this stage SCO considers that an ex ante framework for capex is appropriate, consistent with the transmission rules.
>
> The pricing principles contained in the NEL amendments do not preclude the inclusion of an ex post capex framework in the future. This is best dealt with through the AEMC rule change process.

307 The DNSPs also submitted that, contrary to the submissions made by the Minister, there are no perverse outcomes or incentives resulting from the application of cl S6.2.1(e)(1).

308 According to the Minister's postulate (viz capital expenditure should not be rolled into the RAB if it was not allowed by the previous revenue determination), the capital expenditure incurred by the DNSPs will be unfunded by the extant revenue allowance at the time that it is incurred. This funding shortfall was identified and commented on in some of the extrinsic materials.

309 A DNSP will only receive a funding offset in the future *regulatory control period* which means that it will only commence receiving a return on its prior capital expenditure some five years after that expenditure was incurred. In those circumstances, no rational DNSP would incur unnecessary or inflated capital expenditure. The implication is that only efficient and prudent expenditure would be incurred.

310 In addition, JEN submitted that there was another important policy consideration in play. This is the promotion of investment certainty. JEN submitted that it made good policy sense for investment uncertainties to be reduced and (hopefully) eliminated because the cost of such uncertainties will ultimately be borne by consumers in the form of higher revenue allowances and therefore prices.

311 In its written submissions to the Tribunal, JEN made detailed submissions in support of the ultimate proposition that its actual capital expenditure in the 2006–2010 regulatory period was both prudent and efficient. The Minister did not gainsay the thrust of these submissions. In the circumstances, we do not think it is necessary to traverse the detail of these submissions. However, we accept the broad thrust of them with the consequence that, had it been necessary to form a view as to the prudence and efficiency of JEN's actual capital expenditure in the 2006–2010 period, we would have been satisfied that that capital expenditure was both efficient and prudent.

312 A similar position obtained in respect of each of the other DNSPs.

313 For all of the above reasons, the Tribunal is of the view that the AER correctly interpreted the relevant provisions of the NER (cl 6.5.1 and Sch 6.2) and that the decisions which it made as a consequence of applying that correct interpretation were reasonable in all the circumstances. Accordingly, the Minister's ground of review directed to the capitalisation of related party margins in the RAB fails.

ISSUE 5—ESTABLISHING THE REGULATORY ASSET BASE AS AT 1 JANUARY 2016 (DEPRECIATION)

Introduction

314 Clause 6.12.1(18) of the NER provides that a distribution determination is predicated on the following decision (*inter alia*) made by the AER:

> (18) a decision on whether depreciation for establishing the [RAB] as at the commencement of the following *regulatory control period* is to be based upon actual or forecast capital expenditure.

315 In both its draft decision and the final decision, the AER determined that the depreciation for establishing the RAB as at 1 January 2016 is to be based upon actual (rather than forecast) capital expenditure.

316 The Minister was given leave to challenge that decision.

317 All of the DNSPs supported the AER's decision.

318 The decision constituted a choice by the AER between two available options. The choice which it made was clearly within power.

319 In order to make out this ground of review, the Minister must establish that the exercise of the AER's discretion was incorrect, having regard to all of the circumstances (s 71C(1)(c) and s 71C(2) of the NEL) or that the AER's decision was unreasonable, having regard to all of the circumstances (s 71C(1)(d) and s 71C(2) of the NEL).

The Final Decision

320 At pp 460–461 of the final decision, the AER recorded the submissions which the Minister made to it as follows:

> **9.5.5.3 Submissions on DNSP revised regulatory proposals**
>
> The Minister submitted that the Victorian Government supports the continuing use of depreciation based on forecast capital expenditure (regulatory depreciation) as this is considered to be the approach more suited to the specific circumstances that apply in Victoria, namely:
>
> - the regulatory framework provides an incentive for DNSPs to forecast high capital expenditure
> - the Victorian DNSPs generally underspend relative to forecast whereas DNSPs in other jurisdictions generally overspend relative to forecast
> - the regulatory depreciation for the Victorian DNSPs is therefore generally greater than actual depreciation whereas the regulatory depreciation for DNSPs in other jurisdictions is generally less than actual depreciation
> - Victorian consumers have already paid for regulatory depreciation (as one component of the building blocks revenue) and will effectively pay twice for some depreciation if the (lower) actual depreciation is rolled into the asset base
> - under these circumstances, the regulatory asset base will effectively be larger if actual deprecation is rolled in rather than regulatory depreciation
> - the use of regulatory depreciation rather than actual depreciation places downwards pressure on the capital expenditure forecasts—if the regulatory depreciation is too high relative to actual depreciation, the assets will be written off in the regulatory accounts much earlier than in the statutory accounts (Minister for Energy and Resources, *Submission to the AER*, 20 August 2010, pp.8–9).
>
> In addition, the Minister submitted that the appropriate process to determine whether actual depreciation or regulatory depreciation should be consistently applied in all determinations is through a rule change process (ibid, p 9). DPI reiterated the Minister's view (Victorian Department of Primary Industry, *Further submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–2015*, 12 October 2010, pp.1–2).
>
> EnergyAustralia submitted that the logic of applying actual depreciation for 2016–20 is contrary to the premise of the AER's decision to reject forecast requirements on

> the basis of underspends in the previous period, and the AER has created high incentives for the business to underspend its forecasts but has penalised DNSPs for making decisions in accordance with these incentive arrangements in the previous period (EnergyAustralia, *Submission to the AER*, 19 August 2010, pp.2–3).

321 At p 461, the AER said that, in its view, the incentive framework which applies to forecast capex under cl 6 is relatively weak and general incentives on capex and opex are unbalanced, particularly under the arrangements put in place by the ESCV where depreciation does not form part of the incentive framework. It continued:

> Taking into account the RPP, the AER is of the view that it is required to provide effective incentives or to strengthen the incentives for Victorian DNSPs to seek out efficiencies wherever possible in its capex programs.

322 At pp 462–463 of the final decision, the AER said:

> The AER acknowledges that under an actual depreciation approach, a DNSP retains a greater proportion of the gain or loss of assets with relatively short lives such as IT and non-network general capex in comparison to assets with longer lives. Whilst there may be merit in reconsidering how assets are classified for depreciation purposes, that is a matter appropriately addressed in the context of any potential amendments to the AER's PTRM and RFM and not in this final decision.
>
> As noted in the draft decision, the use of actual depreciation is also consistent with the economic regulation of transmission network service providers under Chapter 6A of the NER and the AER's distribution determinations in New South Wales Australian Capital Territory, Queensland and South Australia (AER, *ActewAGL distribution determination 2009-10 to 2013-14*, April 2008; AER, *New South Wales distribution determination 2009-10 to 2013-14*, April 2009; AER, *Queensland distribution determination 2010-11 to 2014-15*, May 2010; AER, *South Australian distribution determination 2010-11 to 2014-15*, May 2010).
>
> As to the Minister's concerns that the Victorian DNSPs have underspent capex relative to their forecasts, the AER is aware that this occurred during the 2001–05 regulatory period, where actual expenditure was 18 per cent below forecast. The AER notes that an efficiency carryover mechanism was applied to capex during this period, which maintained the strength of the incentives applied to capex. For the 2006–10 regulatory period, there was a slight capex overspend, estimated to be less than 1 per cent above the forecast capex allowance.
>
> Capex underspends and the potential benefits accruing to the Victorian DNSPs appear to be at the heart of the Minister's and DPI's concerns. In this regard, the AER notes that the revealed cost approach, whereby actual expenditures provide a good indicator of efficient costs in the future, relies on an effective incentive framework.
>
> That said, the AER does not agree with EnergyAustralia's comments on this issue as the approach used by the AER to test forecasts of capital expenditure did not rely solely on historical expenditure. The AER's approach is set out in detail in chapter 8.
>
> In response to the Minister's and DPI's suggestion regarding a potential rule change process to determine whether actual depreciation or regulatory depreciation should be consistently applied, this is a matter for the AEMC. Clause 6.12.1(18) of the NER

provides the AER with discretion on whether depreciation for establishing the RAB is to be based on actual or forecast capital expenditure. While the AER does not view consistency as an end itself, it is an underlying rationale for the establishment of national regulatory arrangements, and as noted above, its view on the desirability of the use of actual depreciation reflects that capex incentives are relatively weak if depreciation is not included in the incentive framework.

9.5.5.5 AER conclusion

The AER determines that actual depreciation will be used to establish the opening RAB for the 2016-20 regulatory control period for the Victorian DNSPs.

9.6 AER conclusion

The AER has reviewed the Victorian DNSPs' proposed opening RAB values and the cost inputs to their RFMs for the 2006–10 regulatory period and has cross checked these against their regulatory accounting statements. The AER has identified the following issues and made adjustments for them accordingly:

- reconciliation of data inputs (as noted in section 9.5.1)
- adjustments arising from 2005 expenditure estimates (9.5.2)
- inflation methodology for the RAB forward model (as noted in section 9.5.3)

In accordance with clause 6.12.1(6) of the NER, the AER has determined opening RAB values for the Victorian DNSPs as at 1 January 2011. In determining these values, the AER considers it has done so in a manner which will or is likely to contribute to the achievement of the NEO. The AER has also had regard to the revenue and pricing principles.

These values are set out in table 9.6 and are used as inputs to the PTRM to determine the Victorian DNSPs' annual revenue requirement during the 2011–15 regulatory control period.

The AER has also determined, under clause 6.3.2(a)(2) of the NER, that it will apply the same method to index the RAB as that used to escalate the form of control mechanism over the 2011–15 regulatory control period. This forms part of the calculation in determining the value of the opening RAB for the 2016–20 regulatory control period.

In accordance with clause 6.12.1(18) of the NER, the AER has determined to use actual depreciation for establishing the RAB for the commencement of the 2016–20 regulatory control period.

The AER's decision on the opening RAB can also be found in the distribution determinations for CitiPower, Powercor, JEN, SP AusNet and United Energy.

The Minister's Submissions

323 The Minister submitted that:

(a) Clause 6.12.1(18) gave flexibility to the AER to choose between depreciation of actual expenditure and depreciation of forecast expenditure, depending upon the circumstances of the jurisdiction in question at the particular time the decision was called for.

(b) Victorian DNSPs generally underspend capex in relation to forecast capex.

(c) In circumstances where a DNSP underspends capex in relation to forecast capex, if depreciation is applied to forecast capex for the relevant period, the regulatory allowances for that DNSP in the next regulatory control period will be lower than those which it would have received had depreciation been applied to actual capex. In those circumstances, the application of depreciation to forecast capex places downward pressure on the DNSPs' capex forecasts which is to the long-term benefit of consumers of electricity. The reverse is true if the DNSPs generally overspend capex in comparison with forecast capex.

(d) The AER failed to consider proposition (c).

(e) The AER made errors when it explained why, during the 2001–2005 regulatory period, actual capex for the DNSPs was 18% below forecast capex and when it sought to apply the *"revealed costs method"* to capex.

(f) The AER's reasons for making the decision which it made are misconceived.

324 The Minister filed and served Reply Submissions dated 24 June 2011 in which the essential submissions summarised at [323] above were dilated upon at great length. Those Submissions remain with the Tribunal file. We do not think that it is necessary to traverse those submissions in detail.

The DNSPs' Submissions

325 JEN, UED, CitiPower and Powercor all addressed this ground of review raised by the Minister. All except CitiPower and Powercor did so in writing without seeking to amplify their submissions orally. CitiPower and Powercor made brief oral submissions in addition to their written submissions.

326 CitiPower and Powercor submitted that, under the depreciation of forecast capex approach, the benefits of any capex efficiency gains and the penalties for any capex inefficiencies are all passed through to consumers. There is no sharing of the benefits of capex efficiencies and the detriments of capex inefficiencies as between the DNSPs, on the one hand, and consumers, on the other hand. By way of contrast, depreciation of actual capex involves a sharing of the benefits of capex efficiencies and the detriments of capex inefficiencies between DNSPs and consumers. CitiPower and Powercor submitted that the

Minister's reliance upon the proposition that depreciation of actual capex provides an incentive to DNSPs systematically to over-forecast is misconceived. CitiPower and Powercor emphasised that, during the regulatory process, the AER was obliged to review and consider whether the forecast capex propounded by the DNSPs met the relevant regulatory criteria. The Minister's submissions proceeded upon the basis that the DNSPs have a complete discretion in relation to their forecasts which is plainly not the case.

327 JEN submitted that the Minister's primary argument failed to take account of the fact that any underspend by the DNSPs is likely to reflect improved efficiency of capital expenditure which, in turn, will make consumers better off overall. Further, there was no reason to assume that in the current *regulatory control period* the DNSPs would systematically underspend capex.

328 UED confined itself to submitting that the Minister's submissions simply failed to make out any ground of review.

The AER's Submissions

329 The AER made the following submissions:

(a) By specifying in one distribution determination the method of depreciation to be applied in determining the opening RAB at the next determination, the effect of cl 6.12.1(18) is to provide all DNSPs with clear guidance as to the RAB depreciation consequences of capital investment decisions that they may make in the *regulatory control period* which is operative between the dates of the two determinations.

(b) The NER does not lay down any presumption in favour of one or other method for depreciating the RAB. The exercise of the AER's discretion is only constrained by the terms of the NEO and the need to pay due regard to the RPP.

(c) The AER took account of and did not ignore the Minister's submissions made to it. This is made perfectly plain by the AER in its draft decision and repeated in the final decision.

(d) The AER did not make the factual errors which the Minister suggests it did make.

Decision

330 The decision which the AER made in relation to the method of RAB depreciation to be deployed as at 1 January 2016 was, as all parties have submitted, a decision which it was required to make pursuant to cl 6.12.1(18) of the NER. That clause gave the AER two options. It chose one of them.

331 The Minister directed two broad challenges to the AER’s decision. The first challenge raised a matter which was squarely within the exercise of discretion which had been entrusted to the AER under the NER. The Minister suggested that the AER had failed to appreciate the consequences for consumers of electricity in Victoria of a decision to choose depreciation of actual capex (rather than depreciation of forecast capex) in circumstances where the DNSPs historically have over-forecast in relation to actual capex in any given period. The Minister’s concern was squarely addressed by the AER. It correctly pointed out that the long term interests of consumers of electricity would nonetheless be served, even in the hypothetical circumstances posited by the Minister, because in a regulated environment it was very likely that persistent underspending in relation to forecast capex probably signified efficient and prudent capex on the part of the DNSPs.

332 The second broad challenge made by the Minister involved allegations that the AER had committed a number of factual errors.

333 The first error relied upon by the Minister was that the AER had attributed the over-forecasting which had occurred in the 2001-2005 regulatory period to the application of the efficiency carry-over mechanism to capex and that the presence of this mechanism was the reason that the strength of the incentives applied to capex had been maintained. The AER, however, did no such thing. The AER did not connect the underspend to the application of an efficiency carry-over mechanism. It merely observed that such a mechanism was in place during the relevant period.

334 The next factual error relied upon by the Minister was that, during the 2006–2010 regulatory period, there was a capex overspend of less than 1% above the forecast capex. The Minister suggested that this factual assertion was incorrect for reasons which are set out at par 105 of his submissions. Unfortunately, those reasons simply did not make out factual error.

335 The final factual error relied upon is that there was no evidence before the AER to support its conclusion that capital expenditure incentives are relatively weak if an actual depreciation approach is not included in the incentive framework. However, the AER explained its reasons for coming to that conclusion and those reasons appear to us to be perfectly rational.

336 In our judgment, the Minister has fallen well short of demonstrating either of the grounds of review upon which he relied. The AER applied the appropriate principles and the decision to which it came was perfectly open to it on the material before it. The mere fact that it may also have been open to the AER to choose the other available option does not render the choice which it actually made erroneous.

337 The Minister has failed to make out any ground of review in respect of the AER's decision in relation to RAB depreciation.

ISSUE 6—INDEXATION OF THE REGULATORY ASSET BASE FOR INFLATION

The Relevant Steps in the Regulatory Process and the Present Question

338 By the date when the final decision was made (29 October 2010), only one of the DNSPs (JEN) maintained a contention that the AER had erred in its approach to the question of indexing the RAB for inflation in its draft decision.

339 In their initial regulatory proposals, each of UED, CitiPower and Powercor had indexed its 2006 opening RAB by applying the CPI increase over the same interval that the AER adopted in the final decision viz September 2003 to September 2009. SP AusNet had sought an additional six months indexation for inflation in respect of the period from March 2003 to September 2003. In its initial regulatory proposal, JEN escalated its opening RAB as at 1 January 2006 by six and a half years in order to take account of inflation right up to the commencement of the current *regulatory control period* (1 January 2011). The period in respect of which this escalation took place was the period from 1 July 2004 to 31 December 2010.

340 In its draft decision, at pp 447–448, the AER said:

9.5.3 Escalation rate for RAB roll forward

The NER provides that the roll forward of the RAB be adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism during the preceding regulatory control period (NER, cl.6.5.1(e)(3)). The NER also requires the AER to specify in a building block determination the method of how indexation will be applied to the RAB (NER, cl.6.3.2(a)(2)).

CitiPower, Powercor and United Energy have applied the Australian Bureau of Statistics (ABS) weighted average of eight capital cities, September to September annual CPI. This was consistent with the approach used by the ESCV in the 2006 EDPR for the current regulatory control period.

While SP AusNet has used this same data source, it has applied a March to September annual CPI for 2004 data values. Jemena has used a September to September annual CPI throughout its modelling, with a further forecast six month inflation to convert asset values from July 2010 to December 2010 dollar terms.

AER considerations

The AER questioned Jemena's and SP AusNet's rationale to include additional six months of inflation in their calculations. In its response, SP AusNet stated that there is no additional six months CPI as (SP AusNet, *Response to AER information request*, 5 February 2010).

- all the expenditure benchmarks set in the 2006 EDPR Final Decision are expressed in June 2004 dollars. For the purposes of the RIN, all these data need to be converted into December 2010 dollars to allow the like-for-like comparisons to be made with actual expenditure data
- all actual expenditures are expressed in nominal terms. For the purposes of the RIN, all these data also need to be converted into December 2010 dollars
- applying the 15 month lag methodology will generate the December 2010 dollars for the benchmark and actual expenditure to allow for like-for-like comparison.

Jemena stated that its opening RAB for 1 January 2006 as set out in Schedule 6.2.1 of the NER is valued in June 2004 dollars. Therefore, to appropriately get a closing RAB as at 31 December 2010, in December 2010 dollars (as required by the AER's PTRM) Jemena has escalated the opening RAB for 1 January 2006 by six and a half years over the period (Jemena, *Response to AER information request*, 2 March 2010).

The AER notes that all data in the 2006 EDPR were expressed in real 2004 dollars. The expression of data as at '1 July 2004' in the ESCV's 2006 EDPR reflects the fact that cashflows are assumed to be incurred evenly throughout the year (approximated by a mid year value assumption) and does not imply that data was literally valued as at 1 July 2004. While this is somewhat confusing, the AER has examined the ESCVs' models and confirms that costs prior to 2004 were escalated by the annual CPI as per the control mechanism, which used a September CPI value. In other words, to maintain consistency with the lagged September CPI data used in the control mechanism, this September CPI was used to approximate middle of the year (1 July) values.

Similarly, the inflation adjustment of the RAB proposed by Jemena is incorrect because the annual CPI adjustment is also approximated by September inflation which will be applied to the PTRM. That is, by applying an additional 6 months inflation, Jemena's proposal creates an inconsistency between inflation as applied in the roll forward and in the AER's PTRM.

> The need for consistency has been implicitly recognised by CitiPower, Powercor and United Energy who have escalated nominal costs for the period 2005 to 2010 by annual CPI (September on September) to convert them to real 2010 dollars.
>
> Overall, the AER notes that the ESCV's modelling involves a consistent treatment of CPI between building block revenue requirements, asset values and the CPI-X price control. The AER expects to maintain this consistency throughout the forthcoming 2011–15 regulatory control period, by continuing to apply the ESCV's indexation methodology for the current control mechanism and in the subsequent roll forward calculations under clauses 6.5.1(e)(3) and 6.3.2(a)(2).
>
> **AER conclusions**
>
> The AER has removed the additional CPI applied by SP AusNet (for 2004 data) and Jemena (for 2010 data) as this is inconsistent with the escalation of the current regulatory control period's control mechanism.

341 The following observations may be made about these remarks in the draft decision:

- The use of the Australian Bureau of Statistics weighted average of eight capital cities, September to September annual CPI, was consistent with the approach used by the ESCV in the last ESCV price determination.
- The AER apparently thought that all data in the last ESCV price determination were expressed in real 2004 dollars. According to the AER, it proposed to approximate the annual CPI adjustment by September on September inflation and apply that to the post tax revenue model (**PTRM**). The AER said that, by seeking to apply an additional six months inflation, JEN would create an inconsistency between inflation as applied in the RFM and inflation as applied in the AER's PTRM.
- According to the AER, the ESCV's modelling involved a consistent treatment of CPI between building block revenue requirements, asset values and the CPI – X price control mechanism.

342 None of CitiPower, Powercor or UED took issue with the approach taken by the AER in its draft decision. Indeed, in its revised regulatory proposal, SP AusNet said:

> [SP AusNet] accepts the Draft Determination characterisation of the ESCV CPI modelling underlying the 2006 EDPR Final Decision and has modified its modelling accordingly.

343 The reference to the EDPR Final Decision is a reference to the last ESCV price determination.

344 JEN, on the other hand, maintained its claim to index the 2006 opening RAB values by six and a half years inflation. It was, therefore, the only DNSP which thereafter persisted in a contention that the AER's approach was flawed.

345 In the final decision, the AER maintained its approach. At pp 454–455, it said:

> **9.5.3 Inflation rate for RAB roll forward**
>
> **9.5.3.1 AER draft decision**
>
> SP AusNet applied a March to September annual CPI to adjust the RAB for actual inflation for 2004 data values. JEN applied a September to September annual CPI throughout its modelling, with a further forecast six month inflation to convert asset values from July 2010 to December 2010 dollar terms.
>
> The AER examined the ESCV's models and confirmed that costs prior to 2004 were escalated by the annual CPI as per the control mechanism, which used a September CPI value. The AER considered that the inflation adjustments of the RAB proposed by JEN and SP AusNet were incorrect because the annual CPI adjustment was approximated by September inflation which will be applied to the asset values and PTRM.
>
> The AER considered it appropriate to maintain consistency with the ESCV's treatment of CPI between building block revenue requirements, asset values and the CPI-X price control throughout the 2011–15 regulatory control period by continuing to apply the ESCV's indexation methodology for the current control mechanism and in the subsequent roll forward calculations.
>
> Accordingly, the AER removed the additional CPI applied by SP AusNet (for 2004 data) and JEN (for 2010 data) as this was inconsistent with the escalation of the 2006–10 regulatory period's control mechanism.
>
> **9.5.3.2 Victorian DNSP revised regulatory proposals**
>
> JEN did not accept the AER's draft decision to disallow six months of additional escalation, to translate its 2006 opening RAB as specified in the NER, to a 31 December 2010 dollar value (JEN, *Revised regulatory proposal*, pp.213–17).
>
> JEN contended that its 2006 opening asset base value of $578.4 million is in 1 July 2004 dollar values. In JEN's view, the fact that the ESCV used September CPI values as the basis for annual escalation does not allow or support any inference about the point in the year at which the dollar values are expressed (ibid., p.214).
>
> In addition, JEN submitted that clause S6.2.1(c)(1) is unambiguous in that it expresses the 2006 opening RAB of $578.4 million in July 2004 dollars. It follows that six and a half years' CPI escalation must be applied to that value to convert it to an end of year (31 December) 2010 value that is consistent with the AER's PTRM (ibid., pp.213–14).
>
> JEN argued that the additional half year's inflation it proposed would not create an inconsistency between inflation as applied in the roll forward and in the AER's PTRM where the annual CPI adjustment is also approximated by September inflation (ibid., pp.215–16).
>
> SP AusNet accepted and modified its modelling in accordance with the AER's draft decision, reflecting the ESCV's inflation modelling underlying the 2006 EDPR final decision (SP AusNet, *Revised regulatory proposal*, p.295).

9.5.3.3 Issues and AER considerations

In response to JEN's submission, the AER considers that the reference to '1 July 2004' in clause S6.2.1(c)(1) of the NER means that cash flows are assumed to be incurred evenly throughout the year, as approximated by a mid year value. Accordingly, the AER does not consider that the opening RAB figure specified in clause S6.2.1(c)(1) was valued as at 1 July 2004. As discussed in the draft decision, the AER has examined the ESCV's models and confirms that costs prior to 2004 were escalated by the annual CPI as per the control mechanism, which used a September CPI value. This September CPI was used to approximate middle of the year (1 July) values to maintain consistency with the lagged September CPI data used in the control mechanism.

The AER considers the inflation adjustment of the RAB proposed by JEN is incorrect because the annual CPI adjustment is also approximated by September inflation which will be applied to the PTRM. Applying an additional 6 months inflation, as proposed by JEN, creates an inconsistency between inflation as applied in the roll forward and in the AER's PTRM. To do so would over-compensate JEN by six months' inflation.

9.5.3.4 AER conclusion

The AER has removed the additional CPI applied by JEN (for 2010 data) which is inconsistent with the escalation of the 2006–10 regulatory period's control mechanism.

346 The principal concern of the AER with the JEN revised regulatory proposal was that, according to the AER, the adoption of that proposal would create an inconsistency between inflation as applied in the RFM and inflation as applied in the AER's PTRM. It suggested that adopting that approach would over-compensate JEN by six months' inflation.

347 It was more than a little difficult to discern from the commentary in the draft decision of the AER and, for that matter, in the final decision, precisely what the AER had done in respect of the indexation of the RAB in order to derive the opening RAB values for the beginning of the current *regulatory control period* (ie as at 1 January 2011).

348 In submissions made to the Tribunal for the purposes of the current review, the AER claimed that, in both the draft decision and the final decision, it had converted the 2006 opening RAB values from September 2003 dollars into September 2009 dollars. It then included those values in its RFM, describing them as being in *"$m Real 2010"*, notwithstanding that the values had been increased for inflation only up to September 2009. It disavowed the proposition that it had applied September on September actual inflation measured by the CPI to the period from September 2009 to June 2010. Such an approach was described by the DNSPs as a *"lagged proxy measure of inflation"*.

349 The starting point of the exercise which the AER carried out was that the RAB values which appeared in the table forming part of cl S6.2.1(c)(1) of the NER for each of the DNSPs, although expressed as at 1 January 2006 in July 2004 dollars, were, in fact, figures derived as at 1 January 2006 expressed in September 2003 dollars.

350 The AER submitted to the Tribunal that, in the table to which we have referred at [349] above, the ESCV had mislabelled the date at which the real value of the relevant dollars had been fixed. The proposition was that the reference to July 2004 dollars was a mistake and should have been a reference to September 2003 dollars.

351 The basis upon which the AER contended that the reference to July 2004 dollars was clearly a reference to September 2003 dollars was that, according to the AER, in the last ESCV price determination, the formula for the control mechanism that would apply to regulate the annual nominal adjustments in distribution tariff levels over the 2006–2010 regulatory period was defined as the annual CPI increase to the September prior to the year for which the tariff adjustment was being made.

352 On the basis that its understanding of the methodology adopted by the ESCV in the last ESCV price determination was correct, the AER proceeded with its proposal to index the RABs for inflation only up to September 2009. Its starting point was, however, September 2003. In doing so, it contended that it had:

(a) Followed the methodology which the ESCV had used; and

(b) Complied with the requirements of the relevant rules contained in the NER.

353 All of the DNSPs now wish to challenge the AER's decision on this point. They wish to argue that the position adopted by JEN is the correct and reasonable position.

354 The AER submitted to the Tribunal that none of UED, CitiPower, Powercor or SP AusNet should be permitted to agitate a ground of review directed to the AER's decision in respect of indexation of their RABs for inflation because they did not take issue with the AER's approach at the appropriate time during the regulatory process. In the submission of the AER, s 71O(2) of the NEL prevents those DNSPs from raising the point now.

355 The AER also submitted, however, that, should JEN succeed in its contentions on this point, difficulties would arise in the AER's modelling. There would be difficulties as between JEN, on the one hand, and the other DNSPs. There would also be difficulties in relation to the way in which the AER's modelling had treated inflation in respect of the DNSPs' forecast opex and capex.

356 None of the DNSPs has directly raised a ground of review suggesting that the AER's indexation of forecast opex and capex for inflation was erroneously carried out. However, in the event that JEN succeeds in respect of the present ground of review, the AER drew the attention of the Tribunal to the fact that the PTRM will have taken account of inflation on one basis whereas the RAB values would be indexed on a different basis.

357 The AER said that, in truth, the issue was a common issue for all DNSPs and could not truly be treated as an issue which concerned only JEN.

358 The Tribunal may need to revisit these additional factors if it determines that JEN should succeed in this ground of review.

359 The DNSPs filed lengthy submissions directed to this issue. In particular, CitiPower and Powercor furnished lengthy submissions in chief and even lengthier submissions by way of reply.

360 The parties also made oral submissions in respect of this ground of review which occupied the best part of one day of the hearing.

361 To some extent, the length of the written submissions has obscured the real issues in play.

362 For this reason, we will endeavour to address the issues as briefly as we can without necessarily making extensive reference to the written submissions filed and served by the parties. We should record, however, that we have read and considered those submissions before addressing the present issue in these Reasons.

The Relevant Provisions of the NER

363 The provisions of the NER which are relevant to the Tribunal's consideration of the present issue are cll 6.4.1, 6.4.2, 6.4.3, 6.5.1 and 6.12.1(6) of the NER. As was the case with other issues concerning the RAB, Sch 6.2 to the NER is also significant.

364 At [62]–[83] above, we have explained the building block approach embodied in the NER. At [254] above, we have set out in full the terms of cl 6.5.1 and at [261] and [263] above we have referred to and extracted the relevant portions of Sch 6.2 to the NER.

365 The effect of cl 6.5.1 and cl 6.12.1(6) of the NER is that the AER must make a constituent decision during the regulatory process on the RAB as at the commencement of the relevant *regulatory control period* in accordance with the requirements of cl 6.5.1 and Sch 6.2. For present purposes, those provisions require that the AER make a constituent decision on the RAB as at 1 January 2011 by preparing and publishing a RFM in accordance with cl 6.5.1 which is to be established by rolling forward the amounts set out in the table which is part of cl S6.2.1(c)(1) of the NER.

366 Under cl 6.4.1 of the NER, the AER is required to develop and publish a PTRM. Clause 6.4.2 of the NER provides that the PTRM which the AER must develop and publish must set out the manner in which the DNSPs' *annual revenue requirements* are to be calculated and requires that the model include (*inter alia*):

(a) A method that the AER determines is likely to result in the best estimates of expected inflation; and

(b) The timing assumptions and associated discount rates that are to apply in relation to the calculation of the building blocks referred to in cl 6.4.3.

367 Under cl S6.2.1(c)(3), when rolling forward a RAB under cl S6.2.1(c)(1), the AER is required to take into account the derivation of the values in the table which is part of cl S6.2.1(c)(1) of the NER from *"past regulatory decisions"* and the consequent fact that they (referring to the values in the table) relate only to the RAB identified in those past regulatory decisions.

368 It seems to us that cl S6.2.1(c)(3) requires the AER to take into account by reference to past regulatory decisions the way in which the values in the table were derived as well as the fact that the contents of the RAB comprise only those assets identified in those decisions.

369 In addition, the AER is required to adjust the values in the table to ensure that, insofar as the regulatory period 2006–2010 is concerned, only actual capex undertaken in that period is included. Clause S6.2.1(c)(2) requires the AER to adjust those values in order to remove estimated capex and include only actual capex.

370 Clause 6.5.1(e)(3) requires that the roll forward of the RAB from the immediately preceding *regulatory control period* to the beginning of the first *regulatory year* of a subsequent *regulatory control period* entails the value of the first mentioned RAB being adjusted for actual inflation:

> … consistently with the method used for the indexation of the control mechanism (or control mechanisms) for *standard control services* during the preceding *regulatory control period*.

371 The critical word in cl 6.5.1(e)(3) is the word *"entails"*. That word, in the present context, means *"involves"* or *"concerns"*. That which is involved in the roll forward is the adjustment of the value of the first mentioned RAB for actual inflation. *"Actual inflation"* involves a retrospective determination of inflation because *"actual"* inflation can only be determined retrospectively. Finally, the requirement of consistency is with the method used for taking account of inflation in respect of the relevant control mechanism for *standard control services* during the preceding *regulatory control period*. In the present case, in respect of the period 2006–2010, that control mechanism was a weighted average price cap.

372 In our opinion, cl 6.5.1(e)(3) requires the value of the RAB as at 1 January 2006 to be adjusted for actual inflation consistently with the method used for the indexation of the weighted average price cap during the 2006–2010 regulatory period.

373 Understood in this way, we do not think that cl 6.5.1 requires the AER to escalate the RAB values in respect of the current *regulatory control period* up to 1 January 2011. It is quite obvious from the whole structure of the NER that, as happened in the present case, the regulatory process is intended to culminate in a final decision from the AER which is delivered some months before the commencement of the new *regulatory control period*.

That being so, given that cl 6.5.1(e)(3) requires that adjustments be made for ***actual*** inflation, it follows that the clause does not require that the values be indexed for the whole of the expiring regulatory period. The point to which escalation will be taken will inevitably be a point in time which is before the commencement of the upcoming *regulatory control period*. We do not accept the DNSPs' submissions that cl 6.5.1 of the NER requires the AER to escalate the RAB values right up to and including 31 December 2010. As the AER submitted, the NER are silent as to the point in time to which the asset values are required to be indexed for inflation.

374 It is for these reasons that the AER must adopt a methodology which is consistent with the methodology adopted for indexing the relevant control mechanisms in the prior regulatory period and which is consistent with the derivation of the values set out in the table which forms part of cl S6.2.1(c)(1) of the NER.

375 Both the AER and the DNSPs descended into considerable detail in their submissions in an endeavour to demonstrate the correctness of their propositions concerning the method of accounting for inflation which had, in fact, been adopted by the ESCV in the last ESCV price determination. The AER said that the ESCV had escalated the RAB values only to September 2003 whereas the DNSPs argued that the ESCV had escalated those values up to 1 July 2004 using a lagged proxy for inflation.

376 We are firmly of the view that, looking behind the table which forms part of cl S6.2.1(c)(1) of the NER in order to undermine the statements made therein is an impermissible exercise. The provisions of cl S6.2.1(c)(1) are quite clear in their import. What must be rolled forward as at 1 January 2011, in each case, is the value stipulated in respect of each of the DNSPs in the table forming part of that clause in accordance with Sch 6.2. In our view, it is not open to the AER to treat the statement made in respect of each DNSP's RAB value to the effect that the value was $x *"as at 1 January 2006 in July 2004 dollars …"* as meaning anything other than what it says. In particular, it is not open to the AER to treat the statement that the figures in the table were expressed in July 2004 dollars as an error and to approach the question of RAB indexation on the basis that the figures in the table were actually expressed in September 2003 dollars. The AER was required to use the RAB values in the table in accordance with the remarks made about them in the table.

377 We pause to observe that, in any event, we are far from convinced that the figures in the table were in fact expressed in September 2003 dollars. In this regard, we simply note that there is considerable force in the submissions made on behalf of the DNSPs that the figures were, as stated, expressed in July 2004 dollars. It is probable that the ESCV indexed the RAB values up to 1 July 2004 by using September on September CPI figures as a proxy for actual inflation in respect of the period from September 2003 to July 2004 (nine months).

378 In proceeding upon the basis that the figures in the table truly represented figures in September 2003 dollars, the AER committed a fundamental error in the approach which it took in relation to the indexation of the DNSPs RABs.

The Correct Approach

379 In order to comply with the relevant requirements of the NER, in respect of the current *regulatory control period*, the AER was obliged to roll forward the RAB values stipulated in the table forming part of cl S6.2.1(c)(1) of the NER by (*inter alia*) adjusting those values for actual inflation consistently with the method used for the indexation of the relevant control mechanism in the 2006–2010 regulatory period.

380 The parties agreed that the method used was to deploy the CPI for the eight capital cities of Australia. Whether the AER is confined to using the CPI for the September on September period or some other annual period is a matter which should be for the AER to determine. But, however it is done, the indexation must cover the period commencing 1 July 2004 and ending on a date prior to the date of the final decision which takes into account actual CPI for the eight capital cities in Australia up to that date. That CPI is the measure of inflation previously chosen by the ESCV.

381 The requirements of the NER do not confine the AER’s consideration of the appropriate annual period year by year inflation to the application of the CPI for the September on September period, although using that period may well make a lot of sense given that the current structure of the NER requires regulatory control periods in the future to commence on 1 January.

382 We do not know whether the exigencies of the AER modelling, given the requirements for consistency dictated by the terms of cl 6.5.1(e)(3), mean that the AER must

factor in historical inflation figures right from the start of the regulatory process for each *regulatory control period*. If the exigencies of the modelling do not require that this occur, we would have thought that the appropriate adjustments could be readily included within the model up to a date which is as close as possible to the promulgation of the final decision. For the current *regulatory control period*, this would be to the end of the September 2010 quarter. However, as we have already stressed, these are matters for the AER.

383 In the end, provided that the end point of the period of escalation is reasonable, in all the circumstances, and is also as close as possible to the date upon which the new *regulatory control period* is to commence, it is a matter for the AER to choose that end point. The DNSPs will not suffer provided that the adjustments for inflation to be made in the next *regulatory control period* commence at the end point to which the values have been escalated in the previous period.

Conclusions

384 The decision made by the AER in respect of the escalation of the RAB of JEN was erroneous and unreasonable in all the circumstances. That decision cannot stand as against JEN.

385 We are not persuaded that we should not grant relief to JEN merely because to do so might affect inputs in the AER's PTRM.

386 As far as the impact of this decision on other DNSPs is concerned, we defer further consideration of that matter and will make appropriate directions for additional submissions to be made in respect of that matter.

ISSUE 7—DEBT RISK PREMIUM (ANNUALISATION AND METHODOLOGY)

Introduction

387 In their applications for review, each of the DNSPs challenged the AER's decision not to annualise the Bloomberg fair bond yield date (**DRP annualisation ground**). In addition, JEN also argued that it was unreasonable for the AER to use the yields from a bond issued by Australian Pipeline Trust (**APT**) (**the APT bond**) to estimate the Debt Risk Premium (**DRP**) for the JEN averaging period (**the JEN DRP methodology ground**).

388 The AER and all of the DNSPs ultimately agreed on a disposition of the DRP annualisation ground. That agreement is embodied in a document styled *"Joint Submissions of the Australian Energy Regulator and the Applicants in relation to DRP Annualisation"* dated 26 July 2011. A copy of that joint submission is attached to these Reasons as Attachment "C". The proposed variation recorded in Attachment "C" in respect of JEN was agreed subject to the reservation that a further variation would be required should JEN succeed on the JEN DRP methodology ground.

389 The orders agreed amongst the parties are set out in paragraphs 14 and 15 of Attachment "C".

390 While the Minister supported the AER's decision in respect of DRP, we do not think that the Minister's brief submissions on the point should stand in the way of the Tribunal giving effect to the agreement reached between the AER and the DNSPs.

391 We propose, therefore, when final orders are made, to give effect to that agreement.

The JEN DRP Methodology Ground

392 The issue here may be shortly stated: Should the DRP for the JEN averaging period be derived from the Bloomberg fair value curve or should it be determined by averaging the estimate provided by the Bloomberg fair value curve and the information in relation to the APT bond with a weighting of 75% given to Bloomberg and 25% to the APT bond. The latter approach is the approach actually taken by the AER in its final decision.

393 Clause 6.5.2 of the NER deals with the concept of return on capital. Clause 6.5.2(b) explains the rate of return of a DNSP and the WACC formula. Clause 6.5.2(c) and (d) address the concept of nominal risk free rate and cl 6.5.2(e) deals with the DRP concept.

394 In its May 2009 Review of WACC Parameters, the AER fixed upon a benchmark credit rating for the relevant comparable bonds of BBB+. In its Statement of Regulatory Intent dated 1 May 2009, the AER determined a maturity period of 10 years for the nominal risk-free rate for the purposes of cl 6.5.2(d).

395 If the Tribunal accepts JEN's arguments, the parties agree that the DRP for JEN will increase to 4.34%.

396 One of the two key inputs in determining the WACC that a DNSP is permitted to earn on its capital is the cost of debt, which is calculated by reference to the nominal risk free rate and a DRP. The DRP is the margin above the risk free rate that investors in a company will require to provide debt funds to that business and which compensates them for the inherent risk in holding the company's bonds.

397 Corporate bonds are issued with a coupon rate and a stated term to maturity. There are several different types of corporate bond. Given the decision which we have reached on the appropriate benchmark group of companies, there is no need to go into the detail of these types of bonds.

398 The critical issue in this part of the proceedings was the selection of the benchmark group of companies' bonds that should be used as a basis from which to calculate the DRP for JEN. The parties were agreed that what needed to be measured was the annualised Australian benchmark corporate 10-year BBB+ bond rate. The notion of a benchmark reference group of bonds is widely used and understood and its use was not in dispute.

399 However the Australian market for corporate bonds is widely regarded as "thin"—that is, few companies issue corporate debt in Australia. There are no BBB+ 10-year corporate bonds on issue in Australia and so the DRP benchmark figure can only be estimated. Therein lies the problem—the AER and JEN do not agree on how this should have been measured.

400 The Tribunal has previously endorsed the Bloomberg fair value (FV) curve in *Application by Jemena Gas Networks (NSW) Ltd (No 5)* (2011) ATPR 42-360 as being the suitable benchmark for estimating the DRP in Australia. A major reason for this is that this curve appears to be accepted by the market as providing accurate estimates of the benchmark corporate bond rate.

401 A FV curve such as the one provided by Bloomberg shows the "line of best fit" (determined by Bloomberg's confidential modelling and accordingly the mechanics of its calculation are not available to outside parties) for the plot of bond yields to maturity against

time to maturity. This curve provides an average yield for bonds of a certain term to maturity for bonds of the risk class used to derive the curve and may be used to estimate the appropriate DRP for a company.

402 The specific matter in dispute in the present review was whether the AER made an error of fact or wrongly exercised its discretion or acted unreasonably in all the circumstances in making its calculation of the DRP, by averaging the Bloomberg FV yield with the yield on a bond issued by APT and, if this inclusion were found not to be incorrect, what weight should be accorded to the APT bond compared with the weight given to the Bloomberg FV curve estimate for the benchmark group of bonds.

403 There was no disagreement between the parties about the accepted practice of comparing like with like—the benchmark group of companies should contain those companies whose bonds enjoy the same or very similar risk classifications (ie adjoining classes, in this case bonds with A-, BBB+ and BBB rankings) by the market as the company for which the DRP is to be estimated. These rankings are provided by widely respected commercial information service firms like Moody’s and Standard & Poor’s according to the perceived financial health of the company and its market risk profile.

404 In order to estimate the DRP for a regulated company, several matters must normally be taken into account:

- The risk class(es) to be included in the reference group for drawing up the FV curve.
- Once the risk classes are defined, whether the bonds of all corporate issuers should be included, or whether only bonds issued by a certain type of company (infrastructure operator, specific industry players, etc) should be considered for inclusion.
- The number of years to maturity over which the curve should be estimated (extrapolation of the curve may be needed if the bonds are relatively short-dated).
- The period over which market yields are to be recorded in order to derive the curve.

405 In the present review, all but the second factor was non-controversial and agreed to as between the AER and JEN.

406 In the corporate bond market in Australia there exist very few issuers of BBB+ corporate bonds with a maturity longer than four years. As the Tribunal noted in *Application by Jemena Gas Networks (NSW) Ltd (No 5)* at [69]:

> 69 The problem is that in Australia there is relatively little corporate bond activity. There are only five issuers of BBB+ bonds in Australia with a maturity of greater than four years and this represents too small a population on which judgments can be made with any real confidence.

For this reason, a larger reference group of bonds is needed to construct a meaningful FV curve. It is not uncommon to include in the benchmark reference group bonds issued by companies with risk classifications immediately above and below the company whose DRP is being estimated and accordingly it was accepted by JEN and the AER that A- and BBB bonds should be included in the reference group used to calculate the FV curve, along with BBB+ bonds.

407 It was also agreed by both parties to extrapolate the FV curve from seven to ten years, given the paucity of long-dated bonds in Australia. Beyond seven years, Bloomberg does not provide FV estimates due to limited data availability. Accordingly, the AER developed an extrapolation methodology to derive 10-year yields, which it considered to be the most accurate approach to extrapolation and this was accepted by JEN.

408 As the DRP is based on the difference between the observed cost of debt and the nominal risk-free rate, the AER traditionally measures the benchmark corporate bond rate over the same averaging period as that used to measure the risk-free rate. An averaging period is used to smooth out normal day-to-day market fluctuations in both the risk-free rate and the benchmark corporate bond rate.

409 The averaging period was agreed between the AER and JEN well in advance of the publication of the final decision. This was necessary to allow JEN to put in place arrangements to hedge the base interest rate component of the cost of debt over the regulatory period. JEN proposed, and the AER agreed to, an averaging period from 19 April 2010 to 31 May 2010.

410 The specific errors that JEN alleges were made by the AER in its final decision in relation to the DRP are as follows. JEN submitted that the AER:

- incorrectly assumed that the yield on the APT 10-year BBB fixed coupon bond was representative of the Australian benchmark corporate bond rate.
- did not estimate the DRP solely by reference to the hypothetical estimate provided by the Bloomberg FV curve but estimated it by using a weighted average of 75% of the Bloomberg FV estimate of the yield for a 10 year bond and 25% of the estimated APT bond yield.
- used the APT bond that was issued on 15 July 2010, after the end of the agreed averaging period, to estimate the DRP in conjunction with the Bloomberg FV estimate, which is inconsistent with cl 6.5.2(e) of the NER.
- relied on the yield of the APT bond over its first 30 trading days as from 15 July 2010, to determine a benchmark corporate bond rate for the agreed averaging period (19 April 2010 to 31 May 2010).
- should not have used the APT bond data because its yield was unusually low.
- in extrapolating the yield on the APT bond back to JEN's averaging period, incorrectly assumed that both the risk-free rate and the margin above the risk-free rate would remain constant over time.
- should not have used the APT bond data because the data were unreliable.
- erred in concluding that no adjustment to the APT bond data was required because:
    - changing market perceptions of the APT Group could vary the APT bond data from the averaging period up to the first 30 days of its trading.
    - the conclusion that there were no discernable market-wide factors that would cause a variation in the APT bond data was not supported by the analysis in the final decision.

411 Before we undertake any assessment of the detail regarding the characteristics of the APT bond, and in particular the last four of these eight issues, we must first determine whether this bond should have been taken into account at all. The question of whether to estimate the DRP of the benchmark reference group bond solely by reference to Bloomberg (as sought by JEN) or with reference to a benchmark based on more than one data source (as done by the AER) is the key element to be determined in this part of the review.

The AER's Submissions

412 The AER submitted that its approach was compatible with the purpose of setting a benchmark under clause 6.5.2(e) of the NER. That is, its estimate:

- was of the rate of return on debt required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by JEN;
- reflected s 7 of the NEL, which states that:

> The objective of this Law 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 (a) price …;

- was consistent with the RPP as it provided JEN with a reasonable opportunity to recover at least its efficient costs.

413 The AER further submitted that in the course of carrying out its regulatory function of estimating the DRP it was obliged to achieve a reasonable balance between these objectives and therefore its averaging of the Bloomberg FV yield and the APT bond yield was consistent with the NEL and the NER and was reasonable in all the circumstances. In its opinion, the best estimate is the one that conforms with all the matters which the AER is required to take into account.

414 The AER is of the view that estimating the DRP of the benchmark bond by reference only to the Bloomberg FV curve would produce an estimate that was not ideal in terms of balancing the interests of consumers and JEN. A major reason for this view was that, in its opinion, the Bloomberg curve had performed counter-intuitively since the Global Financial Crisis. It accordingly sought another source of data that might be more reflective of current market conditions. It was also apparently troubled by the fact that the methodology used by Bloomberg to derive its FV curve was not transparent but was treated as proprietary information, even though the curve was widely used by finance practitioners, and even though the AER itself had previously used Bloomberg FV estimates in other regulatory decisions.

415 It might be thought that the AER included the APT bond estimate in order to derive a DRP that was lower than that derived solely from the FV curve and that its hybrid benchmark provided a better estimate of the DRP. However, the long-term interests of electricity

consumers will not be served if, in the long run, DNSPs are not permitted to recover their efficient costs.

416 In its final decision at p 497, the AER said:

> The primary reason for giving weight to the APT bond as a data source for DRP estimation is that the bond resembles some of the key characteristics of the benchmark corporate bond (that is, it is a 10-year BBB rated bond). The fact that it is a bond issued by a firm with resemblance in the nature and degree of non-diversified risk as that faced by the Victorian DNSPs reaffirms the appropriateness of using this bond as a data source for estimating the DRP for the Victorian distribution determinations.

417 It therefore relied on two main characteristics of the APT bond. First, the fact that APT was an infrastructure company, a matter which the AER considered was important in the determination of the DRP for JEN, itself an infrastructure entity. Second, the fact that its bonds were 10-year bonds, of which there were very few trading in the market, even though its debt rating was BBB (not BBB+).

418 As already noted, a fundamental problem exists in estimating the DRP for the benchmark bond. There are no benchmark 10-year BBB+ corporate bonds on issue in the Australian bond market (and very few issued for shorter terms). In the opinion of the AER, as an estimate of the DRP for the benchmark bond can only be implied as a notional construct from various sources and types of bond market information, there was *"no legal or practical imperative for giving 100% weight to the hypothetical Bloomberg estimate"*.

419 Counsel for the AER argued that it necessarily had to exercise some discretion due to the difficulties of estimating the DRP for a benchmark bond of the same risk class, of which type it claimed there were *"virtually none in the market"*. This, it was asserted, gave the AER *"some latitude or discretion when it comes to estimating the debt risk premium of the benchmark bond"*.

420 The AER claimed that it was possible to perform a *"reality-check"* on the inclusion of the APT bond, by considering the characteristics of APT. The AER noted that its parent APA Group is a *"close comparator"* to the benchmark firm.

JEN's Submissions

421 In contrast JEN argued that cl 6.5.2(e) in the NER should be invoked and that only the Bloomberg FV curve extrapolated to 10 years should have been used by the AER because this curve was supported by data which comprises all issued BBB, BBB+ and A- bonds with a maturity of less than seven years.

422 JEN contended that this clause did not permit or require the AER to weight its estimate of the DRP for the benchmark bond towards any particular bonds issued by any specific company. Rather, it said, the clause obliged the AER to determine the benchmark DRP for corporate bonds generally (that is, all those on issue) with the agreed credit ratings.

423 In its WACC Review Final Decision the AER had developed a conceptual pyramid consisting of four tiers of comparator businesses, the first tier representing the conceptual benchmark. The AER found that there were no comparator firms that satisfied the first or second tier. The APA Group (of which APT is a part) fell into the fourth tier. The AER noted that submissions from all the DNSPs endorsed the inclusion of the APA Group in the comparator set used to estimate the WACC parameters that would apply to the benchmark firm.

424 The AER claimed that this ranking of the APA Group provided a reasonable basis from which to conclude that the DRP of the APT bond represented a more conservative estimate of the efficient costs that an electricity business such as JEN needed because, as an electricity distributor, it could be expected to have more stable cash flows and thereby be able to source cheaper debt than a gas network business such as the APA Group. JEN however contended that the APA Group was not a comparable business because it was placed in the bottom tier.

425 JEN submitted that the activities of the APA Group were not relevant in determining whether the APT bond is an appropriate benchmark corporate bond under cl 6.5.2(e). This clause neither requires nor permits the AER to weight its consideration of benchmark corporate bond rates in favour of bonds issued by DNSPs or similar infrastructure businesses. Rather it mandates that in determining the credit rating level of the benchmark corporate bond, the AER must take account of the nature and degree of non-diversifiable risk faced by JEN.

426 Moreover, JEN submitted, even if the underlying characteristics of the APT bond and its issuer were relevant, the AER's assumption that the APA Group undertakes similar activities and faces similar risks to an electricity business did not rise above mere assertion. It was not the product of careful assessment. The parent APA Group, JEN argued, was engaged in several activities that are unrelated to the business of an electricity distributor.

Decision

427 Once the risk level is determined, the AER is required to determine the benchmark corporate bond rate for bonds generally with that credit rating. It is not appropriate for the AER to focus its consideration further, and separately, on corporate bonds issued by individual businesses.

428 The AER's reliance on a yield estimate for the APT bond to support its conclusion that the Bloomberg FV estimates were likely to overstate the relevant benchmark corporate bond rate coupled with its use of the yield estimate for the APT bond to *"balance"* Bloomberg's FV estimates, is unsound and is inconsistent with the AER's earlier conclusion that the Bloomberg fair value curve appeared to be *"acceptably representative"* of yields on bonds in the agreed risk class up to a maturity of 7 years.

429 The Tribunal has never before endorsed such heavy reliance on a single unit of observation in estimating a benchmark reference bond rate nor has it approved the assignment of a not-insubstantial weight to such a single observation when there already exists an accepted benchmark reference group. We do not propose to do so now.

430 The methodology used by the AER to derive the DRP for JEN's averaging period was flawed in a number of respects.

431 First, the inclusion of the APT bond was without justification. The Tribunal in *Application by Jemena Gas Networks (NSW) Ltd (No 5)* endorsed the suitability of using only the Bloomberg FV curve to estimate a regulated firm's DRP.

432 However, Counsel for the AER claimed that the *Jemena Gas Networks (NSW) Ltd (No 5)* decision does not say that it is impermissible to place some weight on a single bond by virtue of its characteristics. That may well be true, but the absence of such a consideration in

that decision does not imply endorsement of the AER's current position. It must be remembered that in *Jemena Gas Networks (NSW) Ltd (No 5)* the issue was whether the DRP should be estimated through averaging the Bloomberg and CBASpectrum FV curves or whether it was appropriate to use only the Bloomberg curve.

433 What was at stake in *Jemena Gas Networks (NSW) Ltd (No 5)* was which bonds should be used collectively as a reference group to draw up the FV curves – while individual companies were discussed in the context of whether their bonds should be included in the group (and thereby be weighted equally with all the other bonds included in the reference group), it was not at issue whether they should be assessed, and included and weighted separately. Accordingly, there is no decision of the Tribunal which supports the AER's contention.

434 JEN submitted, and the Tribunal agrees, that it was unreasonable for the AER to reject its proposal to rely only on the Bloomberg FV curve and instead to incorporate also the yield from a single bond which it had not demonstrated in any way to be a relevant benchmark or comparator bond. The AER appeared only to rely on the fact that the APT bond was appropriate because it was a 10-year bond issued by a company with infrastructure interests and that it had a lower yield than that predicted by the Bloomberg FV curve.

435 The AER's observation that the APT bond yield lay below the Bloomberg fair value curve did not provide meaningful support for its conclusion that the Bloomberg FV curve was likely to overstate yields (and therefore needed to be pared down). This finding should have suggested to the AER that the yield on the APT bond might have been low for its credit rating, as suggested by Dr Hird, an expert witness for JEN.

436 In addition, there was evidence before the AER to show that the Bloomberg fair value curve provided an accurate representation of the yields on benchmark corporate bonds and that it was widely accepted by market practitioners.

437 The AER's methodology relied heavily on a poorly justified hypothetical yield estimate for an inappropriate bond which was not trading during the JEN averaging period. It could not reasonably rely on the APT bond in determining the DRP for JEN. The AER's decision to rely on the APT bond was inconsistent with the requirements of the NER. We are

not satisfied that the yield on the APT bond was representative of the benchmark corporate bond rate for bonds with a BBB+ rating and maturity of 10 years.

438 A further issue with the inclusion of the APT bond is that a benchmark reference group of bonds is designed to be representative of all bonds in the specified risk class. The AER justifies the special attention given to the APT bond on the basis that, not only is it a ten-year bond, but also that it is highly relevant because it is an infrastructure bond. This misses the point – the notion of a reference group is that it should include corporate bonds as a whole, and not just infrastructure or specific industry bonds, nor should it give particular weight to certain company's bonds. This requirement was stated firmly by the Tribunal in *Jemena Gas Networks (NSW) Ltd (No 5)* at [74]–[75] as follows:

> 74. … The benchmark BBB+ rated bonds necessarily include bonds across all industry types. If we needed to expand the reference group to include differently rated bonds in order to estimate the benchmark, it would seem prima facie inconsistent to exclude bonds on the basis of them not exhibiting certain industry characteristics when the benchmark makes no such distinction.
>
> 75. … classification of bonds by industry categories and the exclusion of bonds other than natural monopoly bonds is not a desirable approach.

439 All of this is not to say, of course, that the APT bond could not have been used by the AER internally to provide a check on the DRP estimate derived from the Bloomberg FV curve, rather than including it in combination with the FV figure to derive the DRP estimate for JEN. But it did not do this—the AER actually included the APT bond in its own right.

440 JEN submitted, and the Tribunal agrees, that its proposal to rely on the Bloomberg FV curve was consistent with cl 6.5.2 of the NER, as it provided for an appropriate representation of the relevant benchmark corporate bond rate. In acknowledging the accuracy of the Bloomberg FV curve up to seven years and noting that the extrapolation methodology used was the most accurate available, the AER effectively conceded as much in the final decision.

441 The Tribunal finds that it was unreasonable for the AER to adopt its novel approach to estimating the DRP. In the circumstances, its departure from JEN's proposal in relation to the DRP was contrary to cl 6.12.3(f) of the NER, which provides that the AER may only amend a value or input used in a regulatory proposal to the extent necessary to enable it to be approved in accordance with the NER. Since the value for the DRP in the JEN revised

regulatory proposal was derived in a way that was compliant with cl 6.5.2 of the NER, no amendment by the AER was permitted under cl 6.12.3.

442 The AER's use of the APT bond to estimate the DRP is therefore inconsistent with the requirements of the NER. Even if this bond had been trading in the JEN averaging period (which it was not), the AER should not have substituted its hybrid approach involving the APT bond for JEN's proposal to use Bloomberg alone. The inclusion of the APT bond subverted both the agreed and the statutorily-imposed methodology for determining the DRP.

Other issues

THE RELATIVE WEIGHTS

443 If we had found the AER not to have acted unreasonably in all the circumstances by including the APT bond separately in the benchmark reference group of bonds in estimating the DRP, we would have had to decide on the appropriate weight to have been given to it. Strictly speaking, this matter does not now arise. However, given the AER's novel approach we think it important to comment on its reasons for assigning a weight to the APT bond.

444 Having made the decision to include the APT bond, the AER had to assign a weight to its yield so that it could be averaged with the yield from the FV curve. It chose a 25:75 weighting, in what appears to have been an entirely arbitrary exercise. In its original Discussion Paper, it developed the case for using the APT bond, and proposed a 50:50 weighting for it and the Bloomberg FV estimate. This was strongly resisted by the industry with the result that the AER changed its position in the final decision to the one now under review.

445 This relative weighting was supported by two main considerations:

- the counter-intuitive performance of the Bloomberg FV curve since the onset of the Global Financial Crisis, giving high estimated bond yields; and
- the fact that the Bloomberg FV curve estimate was mostly derived from bonds with less than seven years to maturity with a credit rating of BBB and A- (adjacent to the BBB+ benchmark credit rating) and the APT bond was a 10-year BBB bond.

446 The AER's weight assigned to the APT bond effectively gave it a much greater weight than any of the other corporate bonds contained in the benchmark Bloomberg index. This approach cannot be justified.

447 When pressed in the hearing for the reasoning behind these relative weights, Counsel for the AER could offer no analytical justification. The APT bond was said to provide additional *"useful relevant information"* and that it was therefore appropriate to place *"some weight"* on it for the purpose of estimating the benchmark DRP. It was acknowledged that there did not exist *"some mathematical precision that the regulator can use"* to assign a weight to this bond. It was a *"gut feel"* that led to this weight being assigned to the qualitative features that were thought desirable in this bond.

448 The AER believed that such a weighted average provided a better estimate of the DRP of the benchmark bond and claimed that, under the relevant laws and regulations, it had *"some latitude"* or discretion in estimating the DRP of the benchmark bond.

449 In the Tribunal's opinion this arbitrary approach by the AER should be rejected. A regulator should not make subjective assessments of key inputs into a formula simply because it likes the feel of them. Even assuming for the moment that inclusion of the APT bond was acceptable, we would have thought that accountability demanded a careful and objective justification for the weight to be assigned to it. At the hearing, the AER conceded that it had carried out no form of sensitivity analysis of what the most appropriate weight should be—it simply fed the chosen value into the formula.

THE APT BOND TRADING PERIOD

450 JEN also criticised the use of the APT bond data to estimate the DRP because it was not trading during the agreed averaging period (19 April 2010–31 May 2010). The APT bond did not commence trading until 15 July 2010. JEN's contention was that it was unreasonable to use the APT bond because there was insufficient information before the AER to allow it to form a view as to its hypothetical yield for the earlier agreed period.

451 It was agreed between the parties that there was no difficulty, in principle, with using *"hypothetical"* bond data. That is precisely what the Bloomberg FV estimate is—any point along the curve is the hypothetical value of a bond's yield in the stated risk class. The parties

had of course agreed on a method by which the Bloomberg curve could be extrapolated to 10 years, but based on an agreed trading period.

452 In the final decision the AER started with a presumption that the APT bond yield would not vary over time and sought evidence to the contrary. At p 511, it said that it had:

> ... found no evidence to suggest that the APT bond was unusual and that current observations of the APT bond were unlikely to be materially different to what would have existed if the bond was traded in earlier periods.

453 JEN submitted that the hypothetical yield of the APT bond could not be extrapolated backwards with a sufficient degree of certainty because bond yields do not remain constant over time.

454 The Tribunal agrees that, in general, it would not be wise to make the presumption that bond yields will be constant over time. Indeed, we would expect yields to vary for many reasons, including fluctuations in the risk free rate due to changes in monetary policy; changing market perceptions of the risk profile of a company; and changes in the supply of debt finance generally, including changes in market-wide perceptions of risk.

455 As for changes in the risk free rate, the AER accepted that it did not adjust for this factor because it used the average yield of the APT bond over the first 30 days of trading and subtracted this value from the risk free rate over the averaging period. At a conceptual level, the AER accepted that using the change to the spread over the first 30 days of trading of the APT bond would be more appropriate because it compared the spread between JEN's averaging period and the first 30 days of trading of the APT bond in considering whether the observations of the APT bond would have been materially different to what would have been observed if the APT bond had traded over the averaging period.

456 As to the changing market perceptions of the APA Group, the AER submitted that this factor was unlikely to warrant any adjustment to the APT bond data because the APT bond had a stable trading history in the period over which the AER had observed its bond yields.

457 The AER could not reasonably have formed a view on all of the factors influencing variations in bond yields, based on the evidence before it at the time of the final decision.

While it did seek to account for changes in market-wide risk factors, it did not account for any other variable which might determine bond yields over time. Importantly, it ignored easily observable variations in the underlying risk-free rate over time and instead assumed that a constant spread (over the risk free rate) will mean a constant yield. Further, it did not consider factors which might affect the spread on the APT bond only and not on the whole market.

458 We find the AER's backwards extrapolation to be fraught with problems. Its methodology involved extrapolating backwards the yield of the APT bond, rather than the spread, implicitly relying on an erroneous assumption as to the constancy of the risk free rate. No information was provided as to how trading conditions in the reference period matched up with those in the first few weeks in which the APT bond traded nor is it really possible to determine accurately how the bond might have traded if it had been issued earlier. Accordingly, the AER's calculation of the hypothetical yield on the APT bond during the JEN averaging period was based on far-from-complete information.

459 The extrapolated APT figures are a mere fiction that bespeaks nothing of actual market trading data and, accordingly, are flawed. The AER should not have used the APT bond data because the bond did not trade during the agreed averaging period. Yield estimates for that bond are not available and it is unreasonable to extrapolate this data backwards to the averaging period to determine a hypothetical rate.

460 Given that we have determined that the inclusion of the APT bond in calculating the DRP for the averaging period was not appropriate, how the contribution of that bond was estimated and extrapolated backwards is of no relevance to our decision. Nonetheless, we think that it is appropriate for the Tribunal to make these additional observations for the benefit of the AER, the DNSPs and other interested parties.

Conclusion

461 The Tribunal emphasises that it is important for the AER to estimate the DRP and other WACC components with rigour and transparency, using comprehensive market-accepted data and offering some degree of certainty about the way in which it will apply the various estimating formulae (including the DRP formula) to a regulated company. Its estimating practices, data sources and reference periods must be well articulated, consistent

and communicated to the parties and must, generally speaking, follow the precedents well-established in previous decisions made by the Tribunal in *Application by ActewAGL Distribution* and *Application by Jemena Gas Networks (NSW) Ltd (No 5).*

462 The Tribunal therefore proposes to vary the AER's decision in respect of the DRP pursuant to s 71P of the NEL, in accordance with JEN's proposal to rely only on the Bloomberg FV curve for the derivation of the DRP. This produces a DRP of 4.34% for JEN.

ISSUE 8—JEN CAPITAL EXPENDITURE (BROADMEADOWS RELOCATION PROJECT)

463 As was the case with DRP annualisation ground, JEN and the AER agreed on the resolution of this issue. In Joint Submissions dated 21 December 2011, a redacted copy of which is Attachment "D" to these Reasons, the AER confirmed that it is open to the Tribunal to conclude that each of the grounds of review relied upon by JEN in its review application relating to this issue had been made out and that, accordingly, the distribution determination in respect of JEN should be varied pursuant to s 71P(2)(a) of the NEL. In par 4 of Attachment "D", the quantum of the agreed adjustment has been masked for confidentiality reasons.

464 The Tribunal is satisfied that the AER's distribution determination should be varied as agreed. There will be orders accordingly.

465 At the hearing before the Tribunal, the AER and JEN informed the Tribunal that it was proposed that the determination in respect of JEN be remitted to the AER to be remade. The 21 December 2011 agreement supersedes this earlier suggestion.

ISSUE 9—DISALLOWANCE OF CERTAIN ENTERPRISE SUPPORT FUNCTION COST CENTRES (JEN)

Introduction

466 In the final decision, the AER disallowed four out of 18 cost centres claimed by JEN to relate to the provision of enterprise support functions (**ESFs**). JEN submitted that the 18 cost centres were corporate costs which consisted of a suite of functions provided by Jemena Limited (JEN's parent) to members of the Jemena Group. At a general level, JEN submitted

that Jemena Limited provided ESFs to entities within the Jemena Group so that economies of scale and scope might be achieved.

467 The ESFs are in the nature of corporate overheads. The aggregate cost of providing each ESF across the Jemena Group is captured in Jemena Limited's financial systems. Jemena Limited uses a whole of business cost allocation (**WOBCA**) methodology to allocate a proportion of the cost of providing each ESF to the members of the Jemena Group, including JEN, on the basis of causal allocators. The use of causal allocators reflects the fact that not all members of the Jemena Group require the same ESFs, or the same ESFs to the same extent.

468 The four cost centres which were disallowed by the AER were:

(a) Energy Investment;

(b) Financial Strategy;

(c) Investment Analysis; and

(d) SP Management Fee.

469 After disallowance of those cost centres was flagged in the AER's draft decision, JEN decided not to press the SP management fee cost centre.

470 For this reason, the present review concerns only the remaining three cost centres referred to in subpars (a) to (c) of [468] above (**the disallowed ESF costs**). In broad terms, the quantum of the disallowed ESF costs is approximately 3.15% of the total amount claimed by JEN for ESFs.

471 In its submissions to the Tribunal, the AER raised what it described as *"a pleading point"*. The AER submitted that, in its review application, JEN had challenged only one of the bases upon which the rejected cost centres had been disallowed (namely that they were not sufficiently connected to the provision of distribution services to be included within JEN's forecast opex) and had not specifically challenged the second basis for the AER's rejection viz that the costs claimed were not those of an efficient or prudent operator in JEN's circumstances.

472 We do not accept that JEN confined its attack on the disallowance of the disallowed ESF costs to the lack of sufficient nexus ground. Quite obviously, there would be absolutely no point in challenging the AER's decision in this way because the decision would inevitably stand, irrespective of whether JEN succeeded in overturning the AER's reasoning based upon the lack of sufficient nexus to the relevant services. We do not think that a fair reading of JEN's review application leads to such an absurd result.

473 Accordingly, we reject the AER's *"pleading point"*.

The Relevant Provisions of the NER

474 The critical provisions of the NER in respect of the current issue are found in cl 6.5.6 of the NER. We have explained that rule and extracted parts of that rule at [77]–[80] above.

475 As the AER submitted in the context of the present issue, forecast opex is one of the building blocks which are gathered together to form the *annual revenue requirement* for a DNSP for each *regulatory year* of a *regulatory control period* (cl 6.4.3(a)(7)). The forecast opex that is used as an input to the PTRM is the amount of forecast opex *"… as accepted or substituted by the AER in accordance with cl 6.5.6"* (cl 6.4.3(b)(7)).

476 A building block proposal must include the total forecast opex for the relevant *regulatory control period* which the DNSP considers is required in order to achieve the *operating expenditure objectives* (as specified in cl 6.5.6(a) of the NER).

477 If the AER is satisfied that the total of the forecast opex reasonably reflects the matters specified in cl 6.5.6(c) of the NER, then it must (and must means must) accept the forecast (cl 6.5.6(c)). If the AER is not satisfied of these matters, it must (and again, must means must) not accept the forecast. In that event, it is required to substitute its own views. In deciding whether or not the AER is satisfied of the matters specified in cl 6.5.6.(c) of the NER, it must have regard to the *operating expenditure factors* which are laid down in cl 6.5.6.(e). We have reproduced the text of subcl (c), (d) and (e) of cl 6.5.6 of the NER at [80] above.

478 For the AER to be in a position to conclude whether it is satisfied or not satisfied of the matters listed in cl 6.5.6(c) of the NER, the AER must turn its mind to and consider,

acting both honestly and reasonably, whether the forecast opex for the *regulatory control period* reasonably reflects the *operating expenditure criteria*. In undertaking that task, the AER is obliged to have regard to the *operating expenditure factors* (as to which see cl 6.5.6(e)).

479 Thus, a DNSP must address in its building block proposal, and include therein, total forecast opex which is required in order to achieve the *operating expenditure objectives*. Once the DNSP has included within that forecast all expenditure which it considers is required in order to meet those objectives, the AER must proceed to evaluate the proposal by applying the criteria in subcl (c), (d) and (e) of cl 6.5.6 of the NER. Clause 6.5.6(a) and cl 6.5.6(b) govern the contents of the regulatory proposal to be advanced by a DNSP. The remaining subclauses of cl 6.5.6 regulate the way in which the AER must deal with that regulatory proposal.

JEN's Regulatory Proposal and Subsequent Responses

480 In its regulatory proposal, JEN identified the 18 cost centres which made up the ESFs. It also provided a copy of a review carried out by PricewaterhouseCoopers of the allocation of Jemena Limited's ESF costs to JEN under the WOBCA methodology.

481 The AER sought further explanations from JEN in relation to these matters.

482 In answer to an information request, JEN furnished further explanations of the three cost centres in issue although, it is fair to say, the descriptions were very general.

The AER's Draft Decision

483 In its draft decision, the AER accepted the inclusion of all JEN's claimed ESF costs in its forecast opex with the exception of the four cost centres referred to at [468] above.

484 At pp 207–208, the AER expressed concern that the primary purpose of the disallowed ESF costs was not for the benefit of electricity consumers but rather for the benefit of JEN shareholders. The AER disallowed these ESFs costs on the basis that JEN had not provided sufficient information to demonstrate that the costs were sufficiently connected to the provision of distribution services as to be recoverable under JEN's standard control operating expenditure forecasts. In addition, the AER noted that, even if there was a

sufficient connection, there remained a question as to whether the ESF costs were efficient costs that would be incurred by a prudent operator in JEN's circumstances.

JEN's Revised Regulatory Proposal

485 In its revised regulatory proposal, JEN accepted the AER's disallowance of the SP management fee. However, it continued to press for allowance of the disallowed ESF costs.

486 In its revised regulatory proposal, JEN advanced three arguments by way of overview. These were:

> First, JEN considers it is not possible to distinguish between activities that are to the benefit of owners and those that are to the benefit of network users …
>
> Secondly, the AER's rejection of the financial strategy costs seems at odds with prudent corporate practices. It is unclear how any firm could comply with reporting requirements of the *Corporations Act 2001* (Cth) without having a general ledger and keeping abreast of changes in accounting standards and developing its systems accordingly. Further JEN could not comply with the AER's own regulatory accounting requirements if these accounts could not be audited back to base accounts …
>
> Thirdly, the AER's view that JEN has not shown that the cost centres are directly related to providing distribution services is not relevant in relation to corporate overheads. By their nature, corporate overheads cannot be allocated directly to a particular business. This is why allocations were required in the first place.

(see p 109 of JEN's revised regulatory proposal)

487 JEN proceeded to provide a further outline description of the Finance Strategy, Investment Analysis and Energy Investment ESFs. In those descriptions, JEN emphasised particular tasks that were said to be performed within each ESF cost centre relating to JEN's regulatory obligations. JEN also responded to the suggestion that the costs in question did not reasonably reflect efficient costs that would be incurred by a prudent operator in JEN's circumstances.

The Final Decision

488 In the final decision, the AER disallowed the Energy Investments, Financial Strategy and Investment Analysis ESF cost centres.

489 The AER stated that those costs were disallowed because they were primarily to the benefit of JEN shareholders and not its customers and were therefore not sufficiently

connected to the provision of distribution services. The AER also said that the JEN revised regulatory proposal did not demonstrate that the disallowed ESF costs were efficient costs that would be incurred by a prudent operator in JEN's circumstances.

490 Accordingly, the AER removed the disallowed ESF costs from JEN's base year operating expenditure. The AER made a corresponding reduction to JEN's total forecast opex for the 2011–2015 *regulatory control period*.

JEN's Contentions before the Tribunal

491 In its review application, JEN relied upon all available grounds of review (see s 71C of the NEL). The AER was at some pains to demonstrate that JEN could not rely upon the ground specified in s 71C(1)(c) of the NEL because the task required of the AER by cl 6.5.6 of the NER did not involve the exercise of any discretion.

492 It seems to us that this point goes nowhere. It does not deal with the other grounds specified in s 71C(1) which were also relied upon by JEN.

493 Another preliminary point taken by the AER was that JEN ought not be permitted to rely upon a Written Submission in Reply which was made available to the Tribunal and to the AER shortly before the oral addresses on this issue because most of the material contained in that Written Submission was not review related matter within the meaning of s 71R(6) of the NEL. Senior Counsel for JEN accepted this proposition. However, he went on to submit that, should the Tribunal ultimately be satisfied that one or more grounds of review had been made out by JEN, it should have regard to the material in the Written Submission in Reply to which objection has been taken in order to satisfy itself that the amounts claimed by JEN in its regulatory proposals were justified. Senior Counsel urged upon the Tribunal that, if it were so satisfied, it should simply make the decision itself and not remit the matter to the AER.

494 Senior Counsel for JEN submitted at the outset that the AER had now made clear (if it had not been made clear earlier) that it did not reject the disallowed ESFs costs on the basis of improper allocation. In other words, the WOBCA methodology which underpinned the allocation of those costs was accepted by the AER. This is no doubt why the PricewaterhouseCoopers review was not referred to in the final decision.

495 The first topic addressed by JEN in both its written and oral submissions involved the question of whether or not the disallowed ESF costs were costs that a prudent operator in JEN's circumstances would require in order to achieve the *operating expenditure objectives* (cl 6.5.6(c)).

496 Under this heading, JEN submitted that:

(a) Many of the functions of the Energy Investments Unit were directly relevant to ensuring that JEN complies with its regulatory obligations and requirements. One such function is its interaction with the AER and various Victorian and Commonwealth government departments and agencies regarding current and future regulatory, safety and service obligations that are, or that may be, imposed upon JEN. Another important function was the carrying out of reviews and assessments insofar as the impact of energy and related policies on the JEN business are concerned. The Unit develops policies and strategies for the JEN business. Another function is that the Energy Investments Unit also has responsibility for approving JEN's regulatory accounts. In addition, the Energy Investments Unit acts as the point of contact and facilitates interaction with government stakeholders during emergency events.

(b) The Financial Strategy Unit ensures that JEN has access to operational and fully supported financial systems. It also provides financial analysis support to JEN in respect of the projects JEN undertakes. Specifically, the Unit develops, updates and maintains Jemena Limited's financial systems in order to ensure that Jemena Limited and its subsidiaries, including JEN, operate financial systems that enable the entities to comply with their obligations under the *Corporations Act 2001* (Cth) (**Corporations Act**) and Australian accounting standards. The Financial Strategy Unit includes a systems team which is responsible for deploying new accounting systems for use by members of the Jemena Group.

(c) The Investment Analysis Unit undertakes budgeting, forecasting and financial modelling on behalf of the Jemena Group. These tasks are essential for the conduct of the businesses of each of the members of the Jemena Group, including JEN. This Unit is also responsible for managing the development of, and ongoing monitoring of, the WOBCA process and policy.

497 JEN also submitted that the ESF costs were efficient. In support of this submission, JEN referred to the UMS Report which benchmarked JEN's historic and forecast opex against comparable network facilities. That report demonstrated that the costs were efficient. The AER should have accepted the findings made in that report but did not do so. The AER did not explain why the findings contained in the UMS Report were not sufficient to persuade the AER that the disallowed ESF costs were efficient costs.

The AER's Submissions

498 In its submissions to the Tribunal, the AER suggested that there was overlap and duplication between ESF costs which it had already allowed in other cost centres and those claimed within the Energy Investments Unit.

499 It made a similar submission in respect of costs in the Financial Strategy Cost Centre.

500 Finally, insofar as the Investment Analysis ESF cost centre was concerned, the AER submitted that, at least in relation to part of the claimed costs, there was not the necessary or sufficient connection with the *operating expenditure objectives* of JEN.

501 The AER also submitted that it was entitled not to be satisfied on the question of the efficiency of the costs of the disallowed ESFs. It criticised the detail contained in the UMS Report and submitted that that detail was not sufficient to satisfy the AER.

502 The AER sought to justify the following propositions which were included in the final decision in respect of ESF costs:

> Further, the AER notes that even if a small fraction of these ESF costs categories could be said to be sufficiently connected to the provision of distribution services, this fraction may be outweighed by the AER's full inclusion of each of the other ESF categories, even though parts of these categories may not be sufficiently connected to the distribution services. For example, the AER notes that a portion of the 'CEO', 'CFO', 'Treasury', 'Taxation', 'Business services', 'Internal audit and risk' and 'Finance improvement' ESF cost categories may relate to shareholder costs, though the AER has not attempted to make an adjustment to these categories. In the JEN final decision, the AER also noted its concern over the full inclusion of the CEO and CFO categories, though similarly, did not attempt to adjust these categories.

503 Having referred to the above passage from the final decision, the AER made the following submissions:

94. In substance, this passage reflects the reality that not all of the Jemena ESFs have the same degree of connection with JEN's achievement of the opex objectives. Where the AER has considered, and either included or excluded, the costs of each ESF cost centre on a cost centre by cost centre basis, it does not follow that **all** of the activities of the allowed ESFs are necessary for JEN to achieve the opex objective. Nor would it be expected to follow that **none** of the activities of the disallowed ESFs is necessary for JEN to achieve the opex objective.

95. In reality, the criterion to be applied must ultimately be one of "sufficient" connection between the activities of a particular ESF (considered as a whole) and JEN's requirements in order to achieve the opex objectives. That is the criterion that informs the AER's submissions addressing each of the energy investments, financial strategy and investment analysis ESFs.

96. JEN's argument impermissibly scrutinises a decision maker's reasons with an eye too keenly atuned to the detection of error (*Minister for Immigration and Ethnic Affairs v Wu Shan Liang* (1996) 185 CLR 259 at 271–272).

97. When read fully and fairly, it is evident that the impugned passage was stated as an <u>additional</u> consideration further to the AER's failure to be satisfied of the requisite nexus based on the information that JEN had provided. This is clear from the fact that the preceding sentence of the final decision was:

> "Accordingly, the AER maintains its draft decision position that the financial strategy, investment analysis and energy investments ESF costs categories are primarily to the benefit of JEN shareholders, not its customers, and therefore are not sufficiently connected to the provision of distribution services to be included within JEN's standard control opex forecast."

98. In that context, even if the Tribunal were of the view that the impugned passage was expressed unreasonably, that would not provide a sufficient basis for the Tribunal to conclude that the rejection of the disallowed ESFs was unreasonable. Having regard to all the circumstances, particularly the other independent reasons for the rejection of the disallowed ESFs, there is not unreasonableness within the meaning of s 71C(1)(d).

Decision

504 It seems to us that the AER's decision in respect of the disallowed ESF costs was based upon errors of fact and was unreasonable in all the circumstances.

505 The ESF costs, of their nature, are corporate overhead costs.

506 Those overheads will, in the first instance, be incurred by Jemena Limited or, in some cases, by other entities within the Jemena Group, and be subsequently allocated to JEN using the WOBCA methodology. The WOBCA methodology was reviewed and justified by PricewaterhouseCoopers and was accepted by the AER. The acceptance of the WOBCA methodology necessarily carried with it acceptance of the proposition that the allocated costs

and charges would be incurred by JEN in achieving the *operating expenditure objectives* as defined in cl 6.5.6(a) of the NER. Once the WOBCA methodology was accepted by the AER, there was really no room for the AER to question further the proposition that the forecast opex did not have the requisite connection to the delivery of distribution services and the achievement of the *operating expenditure objectives*.

507 In addition, there was ample material before the AER for it to be satisfied that the forecast opex met the *operating expenditure criteria* (as to which see cl 6.5.6(c) of the NER). As already noted, those costs and charges satisfied the WOBCA methodology and were benchmarked in the UMS Report. The AER criticised that report upon the basis that it did not break up the aggregate costs into sufficient individual cost centres to enable it to be satisfied that the disallowed ESF costs should in fact be allowed. We are of the view that this conclusion was unnecessarily nit-picking and imposed an unrealistic burden on JEN.

508 Finally, in disallowing the disallowed ESFs, the AER took into account the fact that it had allowed most of the claimed cost centres. It suggested, none too faintly, that in allowing most of those cost centres it had almost inevitably allowed costs which should not have been allowed. It then reasoned that, upon the assumption that it had over-compensated JEN in the area of those costs which it had allowed, it was entitled to be rough and ready in its disallowance of the disallowed ESF costs. This approach is entirely irrational and cannot stand.

509 For all of these reasons, we are of the view that the AER made errors of fact and acted unreasonably in all the circumstances when it rejected the disallowed ESF costs.

510 In light of that conclusion, we are also of the view that we are entitled to have regard to the Written Submissions in Reply made by JEN to the Tribunal in order to satisfy ourselves as to the merits of JEN's claims and the amount which should be allowed in respect of the disallowed ESF costs for the base year 2009.

511 We are satisfied that the disallowed ESF costs should be allowed in JEN's forecast opex. We propose to seek the assistance of the AER and JEN in quantifying the disallowed ESF costs. We will make orders appropriately.

ISSUE 10—GAMMA

512 One of the grounds of review raised by each of the DNSPs in their review applications was the AER's decision on the value of gamma (**gamma ground of review**).

513 As submitted by the parties to the present review:

- Gamma represents the assumed utilisation of imputation credits and is an input into the calculation of the cost of corporate income tax, which is a component of the annual revenue requirement—a higher value for gamma reduces the allowance in the annual revenue requirement for the cost of corporate income tax, ceteris paribus, as it is assumed that more of the corporate tax liability is effectively "recovered" by investors through imputation. Gamma is conventionally calculated as the product of the imputation credit payout ratio (or distribution rate) and the assumed value of distributed imputation credits (theta).
- In the individual final determinations applying to each of the respective applicants, and for the reasons set out in the accompanying final decision document, the AER had determined a value for gamma of 0.5, based on a distribution rate of between 0.7 and 1 and a value for theta of 0.65.

514 In *Application by Energex Limited (Gamma) (No 5)* (2011) ATPR 42-356 at [42], the Tribunal said:

> Taking the values of the distribution ratio and of theta that the Tribunal has concluded should be used, viz 0.7 and 0.35, respectively, the Tribunal determines that the value of gamma is 0.25.

515 That conclusion related to a distribution determination in which the Tribunal was required to decide the value of gamma (the assumed utilisation of imputation credits) for the purposes of cl 6.5.3 of the NER. The decision is, therefore, directly in point. Not only is *Application by Energex Limited (Gamma) (No 5)* directly in point but all of the parties seem now to accept that it is also correct. Unless we were satisfied that that decision was plainly wrong, we should follow it. It is important that, as far as possible, the Tribunal's decisions are consistent.

516 Confronted with the strong likelihood that the Tribunal in the present review would apply the reasoning and decision in *Application by Energex Limited (Gamma) (No 5)*, the

parties to the present review reached agreement as to the disposition of the gamma issue for the purposes of that review. That agreement is embodied in a Joint Submission of the parties dated 11 July 2011. A copy of that submission is Attachment "E" to these Reasons.

517 The Tribunal is satisfied that it should proceed in accordance with the parties' agreement. The final determinations made in respect of each DNSP will be varied so as to incorporate a value for gamma of 0.25.

ISSUE 11—MATERIALITY THRESHOLD FOR NOMINATED PASS THROUGH EVENTS (SP AUSNET)

Introduction

518 In its Revised Regulatory Proposal, SP AusNet proposed a materiality threshold of $250,000 for the nominated pass through events.

519 In the final decision, the AER nominated five pass through events, in addition to those which are specified in Ch 10 of the NER. The nominated pass through events determined by the AER were:

(a) A declared retailer of last resort event;

(b) An insurer credit risk event;

(c) An insurance event;

(d) A natural disaster event; and

(e) A network charges event.

520 At pp 30–32 of the AER's final determination in respect of SP AusNet, the AER said:

> **4 Pass through events**
>
> In accordance with clause 6.12.1(14) of the NER, the AER has decided that the additional (nominated) pass through events listed below are to apply to SP AusNet are listed below.
>
> The AER's considerations, reasons and decision on pass throughs are also set out in chapter 16 of the final decision.
>
> • a declared retailer of last resort event:
>
> A declared retailer of last resort event is the occurrence of an event whereby an existing retailer is unable to continue to supply electricity to its customers

and those customers are transferred to the declared retailer of last resort, and which:

(a) falls within no other category of pass through event; and

(b) materially increases the costs of providing direct control services.

For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs are incurred

- insurer credit risk event:

  An event where the insolvency of the DNSP's insurer, as a result of which the DNSP:

  (a) incurs materially higher or lower costs for insurance premiums than those allowed for in the distribution determination; or

  (b) in respect of a claim for a risk that would have been insured by the DNSP's insurers, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy.

  (c) incurs additional costs associated with self funding an insurance claim, which, would have otherwise been covered by the insolvent insurer.

  For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs are incurred

- an insurance event:

  An insurance event occurs if:

  (a) the DNSP makes a claim on an insurance policy that it holds; and

  (b) the DNSP incurs costs beyond the policy limit for the relevant insurance policy; and

  (c) the DNSP must bear the costs that are in excess of the policy limit; and

  (d) the event materially increases the costs to the DNSP of providing direct control services.

  For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs arc incurred.

  For the purpose of this event, a relevant insurance policy refers to the policy coverage provided through a DNSP's forecast operating expenditure allowance for an insured risk, as approved by the AER in its distribution determination and the reasons for the determination.

- a natural disaster event:

  Any major fire, flood, earthquake, or other natural disaster beyond the control of the DNSP (but excluding those events for which external insurance or self insurance has been included within the DNSP's forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to the DNSP of providing direct control services.

For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs are incurred.

- A network charges event

A network charge pass through event occurs on an event date, if:

(a) during the event period to which the event date relates, the DNSP has incurred or saved or, in respect of the event period referred to in paragraph (i), is likely to incur or save, event costs; and

(b) those event costs are material.

The event costs are:

(c) charges for connection to the transmission system; and

(d) charges under Division 5A of Part 2 of the Electricity Industry Act 2000 (Vic) or rule 5.5(h) of the National Electricity Rules; and

(e) charges the DNSP pays to other DNSPs in respect of the provision of distribution services net of similar charges the DNSP receives from other DNSPs,

to the extent that these costs are not otherwise recoverable under the National Electricity Rules in force at the time the event occurs or when an application in relation to those costs is made under clause 6.6.1 of the National Electricity Rules.

An event date in relation to each event period referred to in paragraphs (f) to (i) is 1 June 2011, 1 June 2012, 1 June 2013 or 1 June 2014 respectively.

An event period is:

(f) from 1 January 2011 to 31 May 2011; or

(g) from 1 June 2011 to 31 May 2012; or

(h) from 1 June 2012 to 31 May 2013; or

(i) from 1 June 2013 to 31 December 2015.

For the purpose of this event, the event costs in respect of an event period are material if the total of those costs has an impact of, or more than, 1 per cent of the smoothed forecast revenue specified in the final decision for the applicable regulatory year(s), pro rata for the applicable event period.

521 In respect of each of the events described in subpars (a) to (d) in [519] above, *materiality* was defined as having an impact of 1% of the smoothed forecast revenue of the regulatory year in which the costs are incurred.

522 In respect of the event described in subpar (e) in [519] above, *materiality* was defined differently. However, the concept of *"1% of the smoothed forecast revenue"* is a common

concept to all definitions of *materiality* used by the AER in respect of the nominated additional pass through events.

523 SP AusNet seeks review of the AER's determination insofar as the setting of a materiality threshold for the nominated pass through events is concerned.

SP AusNet's Contentions

524 SP AusNet filed lengthy Written Submissions dated 28 February 2011 in support of its challenge to the AER's decision in respect of the materiality threshold for additional pass through events. The relevant paragraphs in those Written Submissions are pars 36–132.

525 In submissions made orally to the Tribunal, Counsel for SP AusNet presented his client's case more succinctly and with great clarity.

526 The submissions made on behalf of SP AusNet in respect of this issue may be summarised as follows:

(a) At pp 744–745 of the final decision, the AER said:

> **16.2 Regulatory requirements**
>
> An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks appropriately and incurs additional costs, it would be expected to bear those costs. However, the NER pass through provisions recognise that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs.
>
> The NER specifies certain pass through events that are applicable to all distribution determinations (NER, Chapter 10). These are:
>
> - a regulatory change event
> - a service standard event a a tax change event
> - a terrorism event.
>
> The chapter 10 definition of pass through event provides (in addition to the four events listed above) that 'An event nominated in a distribution determination as a pass through event is a pass through event for the determnation'. This chapter considers which pass through events will constitute additional (or 'nominated') pass through events for the 2011-2015 regulatory control period.
>
> The NER does not provide any specific criteria that the AER is to have regard to in assessing proposed additional pass through events. Accordingly, the AER has developed certain criteria for this purpose, and in developing these criteria has had regard to the National Electricity Objective (NEO) and the revenue and pricing principles contained in the National Electricity Law (NEL).

> The AER has a broad discretion in respect of its decision on the additional pass through events that are to apply in a regulatory control period. It appears that neither the Chapter 10 definition of pass through event nor clause 6.12.1(14) limits the AER's discretion. Support for this position is derived from clause 6.12.3 of the NER which sets out the extent of the AER's discretion in making distribution determinations. Clause 6.12.3(a) states that:
>
> > Subject to this clause and other provisions of this chapter 6 explicitly negating or limiting the AER's discretion, the AER has a discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal.
>
> While clause 6.12.3(f) limits the operation of clause 6.12.3(a), the limit only applies to the AER's refusal to approve an amount or value. A pass through event cannot properly be described as an amount or a value. Accordingly, in exercising its discretion the AER had regard to the National Electricity Objective (NEO) and the Revenue and Pricing Principles (RPP).

(b) The AER's views as to the scope of its discretion misconstrued the requirements of the NER. The AER was limited to amending the value of the materiality threshold proposed by SP AusNet ($250,000) only to the extent necessary to enable it to be approved in accordance with the NER. This is the consequence of the application of the correct interpretation of cl 6.12.1(14) and cl 6.12.3(f) of the NER. The materiality threshold for the additional pass through events nominated in the final decision was part of the AER's decision on those additional pass through events. For this reason, and applying cl 1.7.1 of the NER, the reference to that decision in cl 16.12.1(14) includes the materiality threshold, unless the context otherwise requires (which it does not).

The effect of these submissions is that the AER's decision on the additional pass through events was no decision at all.

(c) Clause 6.6.1(a) provides:

> **6.6.1 Cost pass through**
>
> (a) If a *positive change event* occurs, a *Distribution Network Service Provider* may seek the approval of the *AER* to pass through to *Distribution Network Users* a *positive pass through amount.*

(d) Clause 6.6.1(c) lays down the requirements imposed on a DNSP which wishes to seek the approval of the AER to pass through a *positive pass through amoun*t. Clause 6.6.1(d) and cl 6.6.1(e) spell out the way in which the AER is to deal with applications made to it pursuant to cl 6.6.1(c) of the NER. Clause 6.6.1(i) allows the AER to consult with a relevant DNSP in respect of such matters. Clause 6.6.1(j) prescribes those matters which are relevant to the making of a determination pursuant to cl 6.6.1(d) of the NER.

(e) In Ch 10, Glossary, the concept of *"materially"* is defined for the purposes of the application of cl 6A.7.3 to transmission network service providers (**TNSPs**). There is no corresponding definition in Ch 10 in respect of DNSPs.

(f) In Ch 10, *pass through event* is defined by reference to certain specific events. It is also defined as:

> An event nominated in a distribution determination as a pass through event is a pass through event for the determination (in addition to those listed above).

That is the means by which the pass through events with which we are presently concerned became pass through events.

(g) *Positive change event* is defined in Ch 10 of the NER as:

> For a [DNSP] a *pass through event* that materially increases the costs of providing *direct control services*.

(h) The last sentence of the definition in Ch 10, Glossary, in respect of *"materially"* is in the following terms:

> In other contexts, the word has its ordinary meaning.

(i) In cl 6.6.1(a), when regard is had to the definitions of *positive change event* and *materially* contained in Ch 10, Glossary, of the NER, *materially*, when used in the definition of *positive change event*, has its ordinary meaning.

(j) The concept *materially* must be given meaning by paying due regard to the NEO.

(k) In the case of SP AusNet, additional costs likely to be incurred by it by reason of the occurrence of an additional pass through event as nominated by the AER are likely to matter, and thus be material, to SP AusNet at a level which is considerably below the 1% of smoothed forecast revenue provided for in the final decision.

(l) The imposition of the 1% of smoothed revenue materiality threshold is contrary to the NEO and the RPP. By definition, the subject matter of the present consideration is uncontrollable events. What is required, therefore, in dealing with the current issue is a decision which provides to the DNSP a reasonable opportunity to recover its efficient costs. On the assumption that the 1% materiality threshold is too high, the DNSP is denied that opportunity. Incentivising the DNSPs is an irrelevant consideration in dealing with this subject matter. A DNSP cannot be incentivised to avoid an uncontrollable risk or cost.

(m) By setting the 1% materiality threshold the AER has denied to the DNSPs one of the fundamental pillars to which they are entitled under the NEL and the NER, ie a return on their investment commensurate with risk.

(n) In the case of SP AusNet, over the life of the current *regulatory control period* (2011–2015), the imposition of the 1% materiality threshold could result in many millions of dollars of appropriate compensation being denied to SP AusNet. Such an outcome is utterly unreasonable.

(o) The AER's decision was entirely arbitrary. The Tribunal should infer that it was arrived at simply by transferring to DNSPs the requirements of the NER in respect of TNSPs. No regard was paid to the terms of SP AusNet's regulatory proposal and its claim that $250,000 in administrative costs was material to SP AusNet and thus should be set as the relevant threshold.

The AER's Submissions

527 The AER submitted as follows:

(a) The pass through mechanism is a feature of "incentive regulation".

(b) The NER provide a great deal of flexibility in relation to the pass through mechanism.

(c) The AER has a broad discretion as to the nomination of additional pass through events (including the parameters of the events, such as a materiality threshold) constrained only by the NEO and the RPP in the manner set out in s 16 of the NEL.

(d) Having considered the various submissions and arguments propounded by the DNSPs in their regulatory proposals and revised regulatory proposals, at p 766 of the final decision the AER rejected a "dictionary-style" definition of *materially* and opted for the 1% of smoothed forecast revenue as the appropriate measure of *materiality*. The AER considered that this measure provided greater objectivity and certainty than a dictionary-style definition which would be subject to subjective and variable assessment.

(e) At pp 716–717 of its draft decision, the AER set out criteria that it had developed to assess proposals for additional pass through events. These criteria are reasonable and rational.

(f) Clause 6.12.3(f) does not apply to the constituent decision which the AER made pursuant to cl 6.12.1(14). This is because cl 6.12.3(f) applies only to those decisions specified in cl 6.12.1 which involve the fixing of an amount or value. The nomination of pass through events is not such a decision.

(g) The AER did not determine the materiality threshold by robotically applying the materiality threshold specified in the NER for TNSPs. It was but one (amongst many) factor that the AER took into account.

(h) The approach of fixing on a percentage of smoothed forecast revenue is more likely accurately to reflect materiality than would an approach based upon a fixed amount of administrative costs.

(i) The only constraints upon the exercise of the AER's discretion in respect of the materiality threshold are the NEO, the RPP and s 16 of the NEL. In the present case, all of these provisions have been taken into account appropriately. The AER's decision does not conflict with those provisions.

Decision

528 We think that the requirements of cl 6.12.3(f) do not apply to the decision made by the AER in respect of additional pass through events. We are of that view for the reason submitted by the AER. In any event, even if that subclause is to be interpreted in the way suggested by SP AusNet, we think that SP AusNet has not established that the method chosen by the AER was a method arrived at by a process of reasoning and assessment which breached cl 6.12.3(f).

529 We also agree with the AER that the AER has a broad discretion when it comes to consider the nomination of additional *pass through events* and that that discretion is constrained only by the NEO, the RPP, s 16 of the NEL and the general obligation on the AER to behave rationally and reasonably. The mere fact that other ways of defining the materiality threshold might have been reasonably open to the AER does not render the decision which it made unreasonable or liable to be set aside as an incorrect exercise of discretion. For example, in order to overcome the perceived unfairness embodied in the

AER's specification of the *materiality* threshold in the final decision (expressed, as it is, by reference to each *regulatory year*), the AER might have stipulated for an alternative *materiality* threshold expressed as a percentage of an aggregate sum quantified by reference to the entire *regulatory control period*. Such an alternative would ameliorate the effects of the current prescription (which is expressed by reference to each *regulatory year*) in circumstances where, year by year, costs covered by the definition are incurred but only up to an amount which is (for example) 0.999% of the smoothed forecast revenue of each of those years.

530 Notwithstanding that we might think that such an approach might be a better solution than the one actually chosen by the AER, we do not think that the actual exercise by the AER of its discretion was incorrect or that its decision was unreasonable in all the circumstances. More than a mere difference of opinion is required in order to justify the Tribunal's overturning the AER's decision.

531 In those circumstances, given that the AER has gone to considerable lengths to explain its reasons for coming to the decision which it did in respect of the materiality threshold for additional *pass through events*, SP AusNet bears a considerable burden to satisfy the Tribunal that the exercise of the AER's discretion was incorrect or that the decision made was unreasonable in all the circumstances. It would have to show that there is a want of reason in the process and reasoning undertaken by the AER. In our judgment, it has been unable to demonstrate such a want of reason.

532 For the reasons submitted by the AER, we are of the view that SP AusNet has not made out its grounds of review in respect of this issue. We therefore propose to affirm the AER's decision in respect of the materiality threshold for the additional *pass through events*.

ISSUE 12—THE INSURANCE EVENT ISSUE (SP AUSNET)

533 This issue concerns whether the reworked definition of *"insurance event"* in the final decision which included a rider to that definition confining the costs which might be the subject of a pass through payment as a result of the happening of such an event to costs incurred which exceed the level of insurance cover provided by policies the premiums for which were provided for in SP AusNet's forecast opex for the 2011–2015 *regulatory control period* as approved by the AER was an incorrect exercise of discretion or unreasonable in all

the circumstances or was arrived at as the result of errors of fact made by the AER. SP AusNet also contended that the decision to include the rider should be set aside because SP AusNet had been denied procedural fairness in the process leading to the final decision. The rider excluded from the scope of the additional nominated *pass through event* concerning insurance (**the insurance event**) events which occurred in a prior regulatory period (ie prior to 1 January 2011) and which were covered by insurance policies which were in place prior to 1 January 2011 but which had expired according to their terms by 1 January 2011, even though the financial impact and losses caused by those events are wholly or partly suffered in the 2011–2015 *regulatory control period*.

534 SP AusNet applied to the Tribunal to have the entire hearing of this issue heard in private. The orders for a private hearing sought by SP AusNet were not consented to by the AER. No other party wished to make submissions in respect of that matter.

535 On Monday, 4 July 2011, the Tribunal heard argument as to whether the hearing of the insurance event issue should be held in private.

536 From SP AusNet's point of view, the subject matter of the insurance event issue, insofar as it might be the subject of a claim for a *positive pass through amount* by SP AusNet, in the future, is extremely sensitive. At the conclusion of oral argument on 4 July 2011, the Tribunal indicated to the AER and SP AusNet that it would make the directions sought by SP AusNet with the amendments then sought by the AER in terms of proposed order 1.

537 Subsequently, on 6 July 2011, the Tribunal made formal orders pursuant to s 106 of the Competition Act which reflected the orders which it had indicated it would make on 4 July 2011.

538 On 6 July 2011, before the hearing of the insurance event issue began, the precise terms of the orders made on 6 July 2011 were read out in open session. The effect of those orders was that the hearing of the insurance event issue was held in private.

539 The Tribunal is of the view that its reasons in respect of the insurance event issue should, for the time being at least, be kept confidential to the AER and SP AusNet. This is essentially for the same reasons that led the Tribunal to conduct the hearing of that issue in

private. Accordingly, the Reasons for Decision in respect of the insurance event issue will be delivered in a confidential set of Reasons separate from these Reasons for Decision. As presently advised, the Tribunal does not consider that liberty should be granted to any person to apply for access to those confidential Reasons. That will remain the position unless and until the Tribunal directs otherwise.

ISSUE 13—EFFICIENCY CARRYOVER MECHANISM (VEGETATION MANAGEMENT OPEX) (POWERCOR)

540 One of the grounds of review raised by Powercor in its review application was that, in calculating the efficiency carryover mechanism (**ECM**) amounts arising in the 2006–2010 regulatory period to be included in Powercor's *annual revenue requirement* for each year of the 2011–2015 *regulatory control period*, the AER erred by not making an adjustment for certain expenditure necessarily incurred by Powercor in 2008 and 2009 in respect of vegetation management in order to comply with its mandatory statutory line clearance obligations. Powercor called this ground of review *"the ECM adjustment ground"*.

541 Another ground of review raised by Powercor was that, in determining Powercor's total and *annual revenue requirements* for the 2011–2015 *regulatory control period*, the AER erred by bringing to account a negative amount said to reflect an accrued negative carryover arising in the 2001–2005 period under the ECM of the ORG applicable in that period. Powercor called this ground of review the *"the 2001–2005 accrued negative carryover ground"*.

542 On 7 July 2011, Senior Counsel for Powercor informed the Tribunal that an arrangement had been entered into between the AER and Powercor which would absolve the Tribunal from dealing with these issues on a contested basis. Senior Counsel informed the Tribunal that the arrangement would be reduced to writing and subsequently filed in the Registry of the Tribunal.

543 On 12 August 2011, the foreshadowed document recording the parties' arrangement was filed with the Tribunal. A copy of that document is attached to these Reasons as Attachment "F".

544 It is apparent that the parties have agreed that Powercor has established a ground of review in respect of the ECM adjustment ground and that the adjustments agreed between the parties and described in paragraph 13 of Attachment "F" should now be made as a result of the parties' agreement.

545 Paragraphs 17 and 18 of Attachment "F" provide for alternative dispositions depending upon the Tribunal's decision in respect of the 2001–2005 accrued negative carryover ground which is Issue 15 dealt with in these Reasons at [593]–[619] below.

546 The Tribunal will give effect to the parties' arrangements either by applying the agreed disposition set out in paragraph 17 of Attachment "F" or the agreed disposition set out in paragraph 18 of Attachment "F", depending upon the Tribunal's resolution of the 2011–2005 accrued negative carryover ground.

ISSUE 14—VICTORIAN BUSHFIRE ROYAL COMMISSION NOMINATED PASS THROUGH EVENT (CITIPOWER AND POWERCOR)

Introduction

547 On 7 February 2009, a number of bushfires devastated significant parts of Victoria causing substantial damage to property and loss of life.

548 On 16 February 2009, the Victorian Government established a Royal Commission to enquire into and report on a number of matters associated with the 7 February 2009 bushfires. The Victorian Bushfires Royal Commission (**VBRC**) reported to the Governor of Victoria on 31 July 2010. It made 67 recommendations to the Victorian Government.

549 Seven of those recommendations are directly applicable to the DNSPs and a small number of other recommendations have the potential to affect the DNSPs. The principal recommendations which affect the DNSPs are:

(a) The recommendation that all single-wire earth return (**SWER**) power lines in Victoria and all 22 kv distribution feeders in Victoria with aerial bundled cables be progressively replaced;

(b) A suite of interim measures aimed at reducing electricity-caused bushfires in the period before such a replacement program is completed; and

(c) Proposed amendments to the regulatory framework in Victoria for electricity safety to strengthen Energy Safe Victoria's (**ESV**) mandate, powers and influence in relation to the prevention and mitigation of electricity-caused bushfires and to require it to fulfil that mandate. We shall call these recommendations collectively **the relevant VBRC recommendations**.

550 The Victorian Government quite quickly indicated that it proposed to adopt the relevant VBRC recommendations.

551 There is no doubt that the implementation of the relevant VBRC recommendations will impose substantial costs burdens on the DNSPs. There is little doubt, in our view, that the Victorian Government will substantially implement the relevant VBRC recommendations by directly legislating for them or by causing ESV to implement those recommendations through subordinate legislation (statutory regulation) or statutory instruments of one kind or another.

552 CitiPower and Powercor were concerned that there was no guarantee that, should the Victorian Government act to implement the relevant VBRC recommendations, the substantial costs that would be visited upon them could be recovered through the *pass through event* mechanism embodied in the NER. Faced with what those DNSPs called "substantial business uncertainty", they applied to the AER as part of the regulatory process leading to the final decision for a determination by the AER nominating as an additional *pass through event* for the purposes of the NER the costs of and incidental to the implementation of the relevant VBRC recommendations. In this way, CitiPower and Powercor hoped to remove the business uncertainty which they perceived and to ensure that all of the costs visited upon them by the actions of the Victorian Government and its instrumentalities could be passed on to electricity consumers in Victoria.

553 The AER rejected the application made by CitiPower and Powercor for the nomination of such an additional *pass through event*. It did so, not because it disagreed with the idea underpinning the application made by CitiPower and Powercor that the burden of the implementation of the relevant VBRC recommendations should fall upon electricity consumers, but rather because it took the view that the nomination of an additional *pass through event* was completely unnecessary. The fundamental stance adopted by the AER

was that the costs of implementing the relevant VBRC recommendations will inevitably be passed on to electricity consumers in Victoria through the specified *pass through events* stipulated for in the definition of *pass through event* in Ch 10, Glossary of the NER.

554 CitiPower and Powercor contend that the AER incorrectly exercised its discretion or acted unreasonably when it rejected their application for an additional nominated *pass through event*.

555 In the course of the dealings between CitiPower and Powercor, on the one hand, and the AER, on the other hand, the wording of the definition of the proposed additional nominated *pass through event* was canvassed extensively between the parties. Notwithstanding that circumstance, the parties informed the Tribunal that, should the Tribunal uphold this ground of review, the parties would seek an opportunity to discuss further the wording of the appropriate definition.

556 The Minister supported the AER's decision. He also supported the idea that, should this ground of review be upheld, the Tribunal should afford to the parties (including the Minister) an opportunity to discuss the wording of any proposed definition.

557 The parties filed extensive submissions in support of their respective positions and spent the best part of one day of the hearing making oral submissions.

558 We will endeavour to summarise those submissions without doing them an injustice. However, we do not think it is necessary to traverse them in great detail.

The Contentions of CitiPower and Powercor

559 On 19 October 2010, the Victorian Governor in Council made the *Electricity Safety (Bushfire Mitigation) Amendment Interim Regulations 2010* (**bushfire mitigation amendment regulations**). Those amendments established new requirements for bushfire mitigation plans. As a result, the DNSPs are required to submit to ESV before 1 July each year under s 113A of Div 2A of Pt 10 of the *Electricity Safety Act 1998* (Vic) (**Safety Act**) a bushfire mitigation plan that meets the requirements of the Safety Act.

560 A DNSP must comply with a bushfire mitigation plan for its at-risk supply networks that has been accepted by ESV. A failure to do so is an offence. The expression *"at-risk supply network"* is defined in the Safety Act to mean a supply network or a part thereof that is above land and in a hazardous bushfire risk area (**HBRA**).

561 A substantial portion of Powercor's assets are located in HBRAs. As a result of this new requirement, the inspection cycle imposed upon Powercor will reduce from five years to three years for these assets. The requirement will be imposed upon Powercor through its bushfire mitigation plan.

562 At p 780 of the final decision, the AER said:

> The regulatory change event in the NER provides that a regulatory change event is (among other matters), an event that falls within no other category of pass through event. This means that, in assessing whether or not a regulatory change event has occurred under the NER, the AER would, as a necessary precondition, have already considered whether or not a service standard event, tax change event or terrorism event has occurred. Logically, for the purposes of the VBRC outcomes, it follows that if an event does not qualify as a service standard event (as contended by Powercor above), then the AER would need to assess whether a regulatory change event has occurred.
>
> The AER accepts the view that its initial interpretation of regulatory change event is likely to be too narrow. The AER also acknowledges that, from a policy perspective, it is desirable to permit the pass through of costs of new regulatory obligations, and such costs can be broadly interpreted to include new regulatory obligations that arise during the regulatory control period, including those arising from the VBRC. The AER notes that these changes are likely to come into effect during the forthcoming regulatory control period. However, the AER still considers that several new obligations that arise could still be considered as service standard events. Putting aside the title of the event, they could encompass new obligations that do not necessarily relate to a service standard imposed upon the DNSP. This view has been put forward by EnergyAustralia in its pass through application to the AER for the solar bonus scheme (SBS) event.

563 The AER then referred to the submission of EnergyAustralia made in respect of the SBS.

564 At pp 781–783 of the final decision, the AER said:

> The AER has considered Powercor's concerns, namely, that the VBRC Final Report contemplates that most of its recommendations will be implemented by the ESV by means of the exercise of its functions or powers and that this is not commensurate with the definition of 'regulatory change event' which is restricted to 'regulatory obligations or requirements under an Act or instrument made or issued under such an

Act' and does not encompass 'legal obligations or requirements imposed by an administrative act or decision, such as the acts or decisions of ESV' (ibid., pp. 9–10).

The AER has examined the definition of regulatory obligation or requirement under the NEL (NEL, s. 2D.). The AER acknowledges Powercor's concerns. However, the AER observes that while the recommendations from the VBRC have been made and the Victorian government had indicated that several of the recommendations might be implemented, it is unclear how these recommendations will be given force.

The AER considers that references to 'instrument' in paragraph 2D(1)(b) of the NEL are reasonably broad. This could, for example mean obligations imposed by the ESV, via the ESMS. The AER notes, in particular, that the word 'instrument' is not confined to subordinate legislation as is denoted by the words 'instrument made or issued under or for the *purposes of that Act* (emphasis added)'.

The AER also notes that Powercor has omitted to mention the definition of 'regulatory obligation or requirement' in paragraph 2D(1)(a) of the NEL. It is possible that any obligations imposed on DNSPs arising from the recommendations of the VBRC will fall within one of the relevant subparagraphs, that is, where the regulatory obligation or requirement is–

i. a distribution system safety duty; or

ii. distribution reliability standard; or

iii. a distribution service standard.

Notably, paragraph 2D(l)(a) is not dependent on the existence of legislation or an instrument of any kind.

Turning to the issue of whether or not a regulatory change event has occurred, the AER has further considered the definition of both regulatory change event, and service standard event in the NER. The AER cannot predict whether an obligation or requirement arising from a VBRC recommendation will meet the definition of service standard event. (The AER notes that this would also be the case if the AER nominated an additional event for VBRC recommendations or similar event). However, it would appear, at the very least, from the AER's examination of the VBRC's recommendations that many, if not all of them or, collectively, if they are cast that way by the legislature or the ESV would constitute at least a regulatory change event or events (subject to the materiality threshold being met). The main element that the DNSP would need to demonstrate, apart from the inbuilt materiality threshold, is that the change in regulatory obligation or requirement substantially affects the manner in which it provides direct control services (The AER notes that a similar element exists for the service standard event. That is, both events contain the qualifier that the event must substantially vary during the course of the regulatory control period the manner in which a DNSP is required to provide a direct control service. It is thus also possible that an obligation or requirement arising out of the VBRC recommendations could also constitute a service standard event.) The AER considers that, based on the VBRC's recommendations, this element would be met. However, a definitive assessment on this issue can only be made once the recommendations are enacted.

Given the breadth of the regulatory change event and the AER's views expressed in the preceding paragraph, the AER, while it acknowledges Powercor's concerns about the service standard event, considers that the regulatory change event overcomes these concerns.

The AER will therefore accept a 'regulatory change event' that 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.

The AER also emphasises that the occurrence of a regulatory change event is subject to the caveat that it 'materially increase or decrease the cost of delivering direct control services'. The very nature of this requirement means that the AER cannot predict in advance whether a regulatory change event (or any pass through event for that matter) has occurred. The AER notes, for completeness, that this requirement must also be met (for a second time) to qualify as a positive change event in clause 6.6.1 of the NER, that is, when the AER assesses whether to pass costs through to network users.

On this latter issue, there are stakeholder concerns about appropriate consultation for costs passed through in association with the VBRC (EUAA, *AER Draft Determination on Victorian electricity distribution prices for the period 2011-2015 and distributors revised proposals* p. 37; VCOSS, S*ubmission to the AER distribution price review, draft determination*, pp. 2-3). Under the NER, the AER is able to engage in any consultation as it sees fit when considering the costs to be passed through to consumers (NER, cl. 6.6.1(i)). The AER intends to undertake stakeholder consultation in relation to any costs passed through from the VBRC recommendations.

The other events proposed (for which the DNSPs sought clarification) were:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework/a transfer of customer regulation to national regulatory framework event
- changes to safety regulations introduced by the ESV/changes to bushfire mitigation framework
- changes to exposure limits
- a national broadband event
- an introduction of new regulatory obligations for vegetation management around powerlines event
- an emissions trading scheme event/ a CPRS event
- an AEMO fees and charges event (ibid., pp. 708–710).

The first four events, as they are currently defined by the DNSPs, would likely fall within the NER prescribed events, *where they substantially affect the manner in which direct control services are provided,* and they *materially increase or decrease costs of providing those services*. As to whether they would be regulatory change events or service standard events, the AER notes (as set out above) that any assessment of regulatory change event is necessarily presaged by an assessment of whether a service standard event has occurred. For this reason, the AER cannot confirm which NER defined event will apply. The AER is conscious that the definitions as they stand would be either service standard events or regulatory change events subject to the other requirements, including the materiality threshold in each definition, also being met. In respect of the AEMO fees and charges event, the AER considers that the definition, as it stands, would meet the tax change event definition in the NER, subject to the qualifying materiality threshold. This is because the 'tax change event' definition contained in the NER refers to a change in a 'relevant tax' (NER, chapter 10). A 'tax' is further defined as:

> Any tax, levy, impost, deduction, charge, rate, rebate, duty, fee or withholding which is levied or imposed by an *Authority* (NER, chapter 10).

An 'Authority' is further defined as:

> Any government, government department, instrumentality, *Minister*, agency, statutory authority or other body in which a government has a controlling interest, and includes the *AEMC*, *AEMO*, the *AER* and the *ACCC* and their successors (NER, chapter 10).

> **16.6.2.5 AER conclusion**
>
> For the reasons set out above, the AER does not consider it is appropriate or necessary to include the events above as nominated pass through events for the purposes of this distribution determination. In relation to the VBRC, the AER considers that changes arising from the VBRC will be regulatory change events (Where they substantially affect the manner in which the DNSP is required to provide direct control services.).

565 CitiPower and Powercor argued that the AER recognised the business uncertainty about which they were so concerned but failed to provide a solution to that uncertainty by nominating an additional *pass through event* as sought by CitiPower and Powercor.

566 Central to the fundamental submission advanced on behalf of CitiPower and Powercor is the proposition that the additional costs which will inevitably be incurred by CitiPower and Powercor as a result of the implementation of the relevant VBRC recommendations will not be covered by the standard definition of *pass through event* in the NER.

The AER's Submissions

567 After referring to the relevant definitions in the NER, the AER made the following submissions:

(a) The AER's draft decision and the final decision contained assessment criteria developed by the AER to assist when determining whether or not *pass through events* should be nominated. The AER developed these criteria having regard to the NEO and the RPP.

(b) The criteria which the AER proposed for the assessment of *pass through events* were exposed to consideration by the DNSPs in its draft decision (at pp 716–717). None of the DNSPs objected to these criteria in their revised regulatory proposals and subsequent submissions. Other stakeholders, including user groups, consumer groups and energy retailers, expressed broad support for the AER's approach to pass throughs as outlined in its draft decision.

(c) The assessment criteria were:

(i) The event is not already provided for:

- in the defined event definitions in the NER (and does not conflict or undermine the events defined in the NER);
- through the opex allowance (eg the insurance or self-insurance components);
- through the WACC (events which affect the market generally and not just the DNSP are systematic risk and already compensated through the WACC); and
- through any other mechanism or allowance.

(ii) The event is foreseeable—in that the nature of type of event can be clearly identified.

(iii) The event is uncontrollable—in that a prudent DNSP through its actions could not have reasonably prevented the event from occurring or substantially mitigated the cost impact of the event.

(iv) The event cannot be self-insured because a self-insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic.

(v) The party which is in the best position to manage the risk is bearing the risk.

(vi) The passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

(d) The AER also determined the materiality threshold of 1% of the smoothed forecast revenue in each of the years of the *regulatory control period* for all *pass through events*. This matter was the subject of comment by the DNSPs.

(e) Using the approach set out in this assessment framework, in the final decision, the AER nominated four additional *pass through events* to apply to the DNSPs. These were:

(i) A natural disaster event;

(ii) A declared retailer of last resort event;

(iii) An insurance cap event; and

(iv) An insurer credit risk event.

(f) The AER has developed sensible and rational criteria for the determination of whether an additional *pass through event* will be nominated. It applied those criteria in the present case. It was a legitimate exercise of its discretion.

(g) The implementation of the relevant VBRC recommendations will inevitably either be a *service standard event* or a *regulatory change event* within the meaning of those expressions in the NER. The mere fact that the AER did not commit itself in advance definitively and finally to those propositions does not mean that there is justification for agreeing to the application which CitiPower and Powercor have made for the nomination of an additional *pass through event*.

Decision

568 The relief which CitiPower and Power seek is captured in par 128 of the Reply Submissions which is in the following terms:

> CitiPower and Powercor Australia submit that the Tribunal should make an order varying the Final Determinations regarding CitiPower and Powercor Australia so as to nominate an additional pass through event for the implementation of the findings and recommendations of the VBRC that is defined as follows:
>
> > A **VBRC response event** is a legislative or administrative act or decision occurring in response to the findings and/or recommendations of the 2009 Victorian Bushfires Royal Commission set out in its final report dated 31 July 2010 that:
> >
> > (a) has the effect of substantially varying, during the course of a regulatory control period, the manner in which a Victorian Distribution Network Service Provider complies with its regulatory obligations or requirements, including without limitation by means of effecting a change to legislation, regulations, guidelines, policies, procedures or approved management schemes or plans required under the Electricity Safety Act, or an instrument made or issued under that Act, as amended from time to time; and
> >
> > (b) falls within no other category of pass through event.

569 Those DNSPs also seek an extension of time under cl 6.6.1(k) of the NER to make a further application resulting from further amendments to the bushfire mitigation amendment regulations.

570 The essence of the protection which CitiPower and Powercor seek is that all costs visited upon them as a result of a legislative or administrative act or decision occurring in response to the VBRC final report which has the effect of substantially varying, during the course of the current *regulatory control period* (and perhaps during the course of subsequent

regulatory control periods) the manner in which a DNSP complies with its regulatory obligations or requirements be passed through to Victorian electricity consumers.

571 At first blush, such a definition seems to us not to travel beyond the scope of the standard definition of *pass through event* in the NER. If that be correct, one may ask rhetorically: Why have the specifically nominated *pass through event*?

572 Clause 6.6.1(a) to cl 6.6.1(e) of the NER are in the following terms:

> **6.6.1 Cost pass through**
>
> (a) If a *positive change event* occurs, a [DNSP] may seek the approval of the *AER* to pass through to *Distribution Network Users* a *positive pass through amount*.
>
> (b) If a *negative change event* occurs, the *AER* may require the [DNSP] to pass through to *Distribution Network Users* a *negative pass through amount* as determined by the *AER* under paragraph (g).
>
> **Positive pass through**
>
> (c) To seek the approval of the *AER* to pass through a *positive pass through amount*, a [DNSP] must submit to the *AER*, within 90 *business days* of the relevant *positive change event* occurring, a written statement which specifies:
>
> (1) the details of the *positive change event*; and
>
> (2) the date on which the *positive change event* occurred; and
>
> (3) the *eligible pass through amount* in respect of that *positive change event;* and
>
> (4) the *positive pass through amount* the [DNSP] proposes in relation to the *positive change event*; and
>
> (5) the amount of the *positive pass through amount* that the provider proposes should be passed through to *Distribution Network Users* in each *regulatory year* during the *regulatory control period*; and
>
> (6) evidence:
>
> (i) of the actual and likely increase in costs referred to in subparagraph (3); and
>
> (ii) that such costs occur solely as a consequence of the *positive change event*; and
>
> (7) such other information as may be required under any relevant *regulatory information instrument*.
>
> (d) If the *AER* determines that a *positive change event* has occurred in respect of a statement under paragraph (c), the *AER* must determine:
>
> (1) the *approved pass through amount*; and

(2) the amount of that *approved pass through amount* that should be passed through to *Distribution Network Users* in each *regulatory year* during the *regulatory control period*,

taking into account the matters referred to in paragraph (j).

(e) If the *AER* does not make the determinations referred to in paragraph (d) within 60 *business days* from the date it receives the [DNSP]*'s* statement and accompanying evidence under paragraph (c), then, on the expiry of that period, the *AER* is taken to have determined that:

(1) the *positive pass through amoun*t as proposed in the [DNSP]'s statement under paragraph (c) is the *approved pass through amount* in respect of that *positive change event*; and

(2) the amount of that *positive pass through amount* that the [DNSP] proposes in its statement under paragraph (c) should be passed through to *Distribution Network Users* in each *regulatory year* during the *regulatory control period*, is the amount that should be so passed through in each such *regulatory year*.

573 Before making a determination under cl 6.6.1(d), the AER may consult with the relevant DNSP and others "… *on any matters arising out of the relevant* ***pass through event*** *the AER considers appropriate* (cl 6.6.1(i)).

574 Clause 6.6.1(j) provides:

Relevant factors

(j) In making a determination under paragraph (d) or (g) in respect of a [DNSP], the *AER* must take into account:

(1) the matters and proposals set out in any statement given to the *AER* by the [DNSP] under paragraph (c) or (f); and

(2) in the case of a *positive change event*, the increase in costs in the provision of *standard control services* that the [DNSP] has incurred and is likely to incur until the end of the *regulatory control period* as a result of the *positive change event*; and

(3) in the case of a *positive change event,* the efficiency of the [DNSP]'s decisions and actions in relation to the risk of the *positive change event*, including whether the [DNSP] has failed to take any action that could reasonably be taken to reduce the magnitude of the *eligible pass through amount* in respect of that *positive change event* and whether the [DNSP] has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that *positive change event*; and

(4) the time cost of money based on the *weighted average cost of capital* for the [DNSP] for the relevant *regulatory control period*; and

(5) the need to ensure that the [DNSP] only recovers any actual or likely increment in costs under this paragraph (j) to the extent that such increment is solely as a consequence of a *pass through event*; and

(6) in the case of a *tax change event*, any change in the way another *tax* is calculated, or the removal or imposition of another *tax*, which, in the *AER's* opinion, is complementary to the *tax change event* concerned; and

(7) whether the costs of the *pass through event* have already been factored into the calculation of the [DNSP]'s *annual revenue requirement;* and

(8) any other factors the *AER* considers relevant.

575 In Ch 10, Glossary, the following relevant definitions appear in respect of DNSPs:

approved pass through amount

…

In respect of a *positive change event* for a [DNSP]:

(a) the amount the *AER* determines should be passed through to *Distribution Network Users* under clause 6.6.1(d)(2); or

(b) the amount the *AER* is taken to have determined under clause 6.6.1(e)(3),

as the case may be.

eligible pass through amount

…

In respect of a *positive change event* for a [DNSP], the increase in costs in the provision of *direct control services* that the [DNSP] has incurred and is likely to incur until the end of the *regulatory control period* as a result of that *positive change event* (as opposed to the revenue impact of that event).

pass through event

Any of the following is a *pass through event*:

(a) A regulatory change event;

(b) A service standard event;

(c) A tax change event;

(d) A terrorism event;

…

An event nominated in a distribution determination as a *pass through event* is a *pass through event* for the determination (in addition to those listed above).

positive change event

…

For a [DNSP], a *pass through event* that materially increases the costs of providing *direct control services.*

positive pass through amount

…

For a [DNSP], an amount (not exceeding the *eligible pass through amount*) proposed by the [DNSP] under clause 6.6.1(c).

576 In order to engage cl 6.6.1(a), there must first of all be a *pass through event*.

577 CitiPower and Powercor submitted that it was not certain that the subject matter of the nominated *pass through event* which they seek in the present case is one of the events specified in subpars (a) to (d) of the definition of *pass through event* in Ch 10, Glossary. If it is to be brought within that definition, so they submitted, it must be nominated as such by the AER.

578 On the assumption that an event occurs which falls within the definition of *pass through event*, the second matter which must be satisfied before cl 6.6.1(a) is engaged is that the *pass through event* must be a *positive change event*. This too is defined in Ch 10, Glossary.

579 If the postulated event is a *positive change event*, then the DNSP may seek the approval of the AER to pass through to consumers the *positive pass through amount*. That amount is the amount proposed by the DNSP to the AER under cl 6.6.1(c). It must not exceed the *eligible pass through amount*. This phrase is also defined in Ch 10, Glossary. It is the increase in costs incurred and likely to be incurred until the end of the *regulatory control period* as a result of that *positive change event*.

580 The AER must then consider whether it will approve the amount claimed by the DNSP. If the AER approves that amount, or if it is deemed to have been approved under cl 6.6.1(e), that amount becomes the *approved pass through amount* for the purposes of the NER.

581 In Ch 10, Glossary, the following additional definitions appear:

> ***service standard event***
>
> A legislative or administrative act or decision that:
>
> (a) has the effect of:
>
> (i) substantially varying, during the course of a *regulatory control period*, the manner in which a *Transmission Network Service Provider* is required to provide a *prescribed transmission service*, or a [DNSP] is required to provide a *direct control service*; or
>
> (ii) imposing, removing or varying, during the course of a *regulatory control period*, minimum service

standards applicable to *prescribed transmission services* or *direct control services*; or

(iii) altering, during the course of a *regulatory control period,* the nature or scope of the *prescribed transmission services* or *direct control services,* provided by the service provider; and

(b) *materially* increases or *materially* decreases the costs to the service provider of providing *prescribed transmission services* or *direct control services*.

regulatory change event

A change in a *regulatory obligation or requirement* that:

(a) falls within no other category of *pass through event*; and

(b) occurs during the course of a *regulatory control period*; and

(c) substantially affects the manner in which the *Transmission Network Service Provider* provides *prescribed transmission services* or the [DNSP] provides *direct control services* (as the case requires); and

(d) *materially* increases or *materially* decreases the costs of providing those services.

582 The services which the DNSPs provide are *direct control services* within the meaning of the NER.

583 Given the terms of the relevant VBRC recommendations and the means by which they are to be implemented, we think that inevitably those means will constitute a *service standard event* within the meaning of the NER. CitiPower and Powercor seem to recognise as much. The terms of the definition of the additional *pass through event* which they seek to have nominated essentially mirror the substance of the definition of *service standard event* in the NER.

584 Of course, if those means do constitute a *service standard event* within the meaning of that expression in the NER, they will also constitute a *pass through event* within the meaning of that expression in the NER. This is because a *service standard event* is specifically referred to as one of the events constituting a *pass through event*.

585 If the means by which the relevant VBRC recommendations are implemented do not constitute a *service standard event*, they will almost certainly constitute a *regulatory change event*.

586 The concept of *regulatory obligation or requirement* referred to in the definition of *regulatory change event* is given meaning by the definition of that expression in Ch 10, Glossary, which picks up the terms of s 2D of the NEL. We have extracted s 2D in full at [29] above.

587 Section 2D of the NEL refers to the concept of a *distribution system safety duty*. That expression is defined in s 2 of the NEL as follows:

> ***distribution system safety duty*** means a duty or requirement under an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, relating to–
>
> (a) the safe distribution of electricity in that jurisdiction; or
>
> (b) the safe operation of a distribution system in that jurisdiction.

588 We find it impossible to conceive that any of the relevant VBRC recommendations would be implemented other than through means which are inevitably going to be captured by the definitions of either *service standard event* or *regulatory change event*.

589 For these reasons, we think that the reasoning process, adopted by the AER in justifying its rejection of the application for an additional nominated *pass through event* in the terms of the definition sought by CitiPower and Powercor, is perfectly reasonable and most compelling. The AER ought not and cannot be compelled to nominate an additional *pass through event* the scope of which is merely to repeat the coverage or scope of one of the *pass through events* specifically nominated in the definition of *pass through event* in subpar (a) to (d) of that definition. The AER was entitled to weigh up the alleged business uncertainty and to dismiss it as being of so little real consequence as not to justify the nomination of some additional *pass through event*. The point is brought home particularly starkly when consideration is given to the terms of the definition propounded on behalf of CitiPower and Powercor—a definition which does not travel beyond the scope of the definitions of *service standard event* or *regulatory change event*.

590 For all of these reasons, the Tribunal affirms the decision of the AER in respect of the application made by CitiPower and Powercor for the nomination of an additional *pass through event* in respect of the relevant VBRC recommendations.

591 The AER argued that the terms of the relevant provisions of the NER (cl 6.6.1 and several definitions in Ch 10, Glossary) mandate that the AER can only nominate *pass through events* which require that the event occur in the relevant *regulatory control period* and that the loss (costs) caused as a result of that event be suffered in the same *regulatory control period*. The same principle, if correct, would apply in respect of the events specified in subpars (a) to (d) of the definition of *pass through event*.

592 We see nothing in cl 6.6.1 which imposes on the AER a constraint of the kind described in [591] above. The relevant definitions do not impose such a constraint and there is nothing in cl 6.6.1 which imposes such a constraint. The reference in the definition of *eligible pass through amount* in Ch 10 to *"… costs … that it is likely to incur until the end of the* ***regulatory control period*** *…"* does not justify the conclusion for which the AER argued. The distinction made at the end of that definition between costs and revenue does not justify that conclusion either. The definition simply does not address the point at all.

ISSUE 15—2001–2005 ACCRUED NEGATIVE CARRYOVER (POWERCOR)

Introduction

593 Powercor incurred a negative carryover in respect of its performance in the regulatory period 2001–2005. That negative carryover was not applied to Powercor's revenue in the 2006–2010 regulatory period. The AER took the view that that negative carryover was held over until the current *regulatory control period* (the period 2011–2015). Powercor is the only DNSP in this position.

594 The AER identified the issues calling for determination in respect of this matter in the following way:

(a) In circumstances where:

(i) Powercor had accrued a net negative carryover from the application of the ECM that applied to its expenditure in the 2001–2005 regulatory period (**2001–2005 ECM**);

(ii) The accrued negative carryover arising from the application of the 2001–2005 ECM had not been applied in reduction of Powercor's allowed revenues during the 2006–2010 regulatory period; and

(iii) Powercor accrued positive carryover amounts projected for various years in the 2011–2015 *regulatory control period* arising from the application of the ECM that applied to its expenditure in that period (**2006–2010 ECM**)

did the AER have power under:

(iv) Section 2.3.4 of the AER's "electricity distribution network service providers Efficiency Benefit Sharing Scheme June 2008" (**EBSS**) in conjunction with cl 6.4.3(a)(5) and cl 6.4.3(b)(5) of the NER; or

(v) Clause 6.4.3(a)(6) and cl 6.4.3(b)(6) of the NER

to apply Powercor's 2006–2010 positive carryover amounts subject to (ie net of, or after subtracting) Powercor's 2001–2005 ECM accrued negative carryover, and allocate resulting adjustments to particular years, in the course of determining Powercor's *annual revenue requirements* for the *regulatory years* of the *regulatory control period* 2011–2015; and

(b) If the AER had such a power, did it exercise its discretion incorrectly or was the distribution determination in relation to Powercor unreasonable, by reason of the AER having so applied that accrued negative carryover.

595 We have extracted cl 6.4.3(a) at [67] above. We have also extracted cl 6.4.3(b)(5) and cl 6.4.3(b)(6) at [231(f)] above.

Powercor's Contentions

596 After referring to cl 6.4.3(a)(5), cl 6.4.3(a)(6), cl 6.4.3(b)(5) and cl 6.4.3(b)(6) of the NER, Powercor pointed to cl 6.5.8 of the NER. Powercor submitted that, under the building block approach to regulation, in the absence of an ECM, a DNSP would receive a benefit from improvements in its efficiency during the regulatory period in which the gain occurs because its actual expenditure would be less than the forecast expenditure underpinning the regulator's decision (ie the DNSP would be permitted to retain the difference between its allowed revenue and the actual expenditure incurred). In the regulatory period following the period in which the efficiency gain is made, however, as expenditure forecasts are usually dependent in part on past expenditure, the efficiency gain is reflected in lower revenue allowances and thus the benefit of the gain is passed through to electricity consumers.

597 ECMs are designed to further strengthen the incentives for a DNSP to achieve efficiency gains and thereby deliver a greater benefit to electricity consumers in subsequent periods through lower prices (in present value terms). They do this by seeking to deliver a fair sharing of the benefits achieved through efficiency gains (and the detriment from efficiency losses) between DNSPs and electricity consumers.

598 ECMs operate by carrying forward efficiency gains and losses for a given number of years following the achievement of those gains and losses by reflecting the gain or loss in the expenditure forecast for the subsequent year.

599 An ECM can only have a positive effect (ie can only further strengthen a DNSP's incentives to make efficiency gains) if all relevant aspects of the ECM are understood by the DNSPs at the time they are incurring the expenditure in the period in respect of which the ECM carryover amounts are to be calculated.

600 In its 2001–2005 price determination, the ORG:

(a) Determined the ECM carryover amounts arising from expenditure incurred in the 1995–2000 regulatory period that were to be included in the revenue requirements for the DNSPs for the 2001–2005 regulatory period; and

(b) Set out the ECM (**ORG's ECM**) to be applied to the expenditure incurred in the 2001–2005 regulatory period in order to calculate the 2001–2005 ECM carryover amounts to be included in the DNSP's revenue requirements for the 2006–2010 regulatory period.

601 The ORG's ECM (insofar as it related to opex) provided that any efficiency gains (or losses) would be retained by the DNSPs for five years after the year in which the gains (losses) were achieved.

602 The ORG stated that a "zero floor" would be set on the ECM carryover amount in any one year of the 2006–2010 regulatory period. That is, there would be no negative carryover in any year of that period. The carryover amount for the 2001–2005 regulatory period would be set to zero where the carryover amount would otherwise have been negative.

603 At pp 89–90 of its determination, the ORG said:

> The Office has concluded that it is neither possible nor appropriate to make permanent now the treatment of any accrued negative carryover amounts at the end of the 2001–05 regulatory period. Rather, it considers that the treatment of any accrued negative carryover between regulatory periods should necessarily be a subject for discretion, and one that will in part depend on the circumstances that gave rise to the accrued negative amount.

604 In the last ESCV price determination, the ESCV:

(a) Determined the ECM carryover amounts arising from expenditure incurred in the 2001–2005 regulatory period that were to be included in the revenue requirements of the DNSPs for the 2006–2010 regulatory period; and

(b) Set out the ECM (**ESCVs ECM**) to be applied to the DNSPs in respect of expenditure incurred in the 2011–2015 regulatory period.

605 The ESCV did not apply the "zero floor" as described by the ORG. Rather than applying implied negative carryover amounts only to subsequent years in the regulatory period, the ESCV applied a "net present value" approach to the zero floor. Where the sum of accrued efficiency carryover amounts for the 2001–2005 regulatory period was negative in net present value terms, the ESC set to zero the ECM carryover amount to be applied to revenues for each year of the 2006–2010 regulatory period.

606 Applying this approach, the ESCV calculated that, during the 2001–2005 regulatory period, Powercor incurred an efficiency loss or negative carryover of $22.9 m (in $2004). For the purposes of setting the 2006–2010 expenditure allowances in the last ESCV price determination, no ECM carryover amount in respect of the 2001–2005 period was applied.

607 The ESCV gave two reasons for the decision which it made. First, its approach ensured that any rewards for efficiency gains are calculated net of any penalties for efficiency losses to the extent that there is not a negative applied to the revenue requirement for the period. Second, in some instances, the continued carryover of accrued negative amounts into subsequent regulatory periods may weaken the incentive properties of the mechanism.

608 In June 2008, the AER published an ECM that was to apply to the DNSPs: This is the EBSS. It published that ECM in its capacity as the regulator under the last ESCV price determination.

609 In its final EBSS decision, the AER said:

> The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.

610 In the final decision, the AER decided that, for the purposes of determining Powercor's total and *annual revenue requirements* for the 2011–2015 *regulatory control period*, it was entitled to include a negative amount of $22.9 m in real 2004 dollars said to reflect a 2001–2005 accrued negative carryover that the AER decided was to be deducted from Powercor's *annual revenue requirements*. Powercor submitted that nothing in the NER authorised this decision. It submitted that:

(a) Clause 6.5.8 of the NER does not cover an ECM which compares the expenditures incurred in, and the forecast made, during any regulatory period prior to the current *regulatory control period* (ie the one which commenced on 1 January 2011).

(b) Clause 6.4.3(a)(5) does not cover revenue increments or decrements arising from the application of the ORG's ECM or the ESCV's ECM. Nor does cl 6.4.3(a)(6).

The AER's Submissions

611 In its Written Submissions, the AER did not endeavour to support its decision by reference to s 2.3.4 of the EBSS and cl 6.4.3(a)(5) and cl 6.4.3(b)(5) of the NER. For this reason, we do not propose to address those sources of power. We should record that we do not think that the provisions relied upon authorise the AER to act as it did.

612 The AER submitted that cl 6.4.3(a)(6) and cl 6.4.3(b)(6) supported the decision which it has made.

Decision

613 This issue essentially raises the same considerations as were raised and determined at [200]–[247] above in relation to Issue 3—Close out of the ESCV's "S" Factor Scheme. As far as the present issue is concerned, different extrinsic material has been relied upon by the AER. That material appears to us to be entirely neutral on the question which we have to decide.

614 For essentially the same reasons as we rejected the AER's contentions in respect of Issue 3, we also reject them in respect of this issue. We should add that, in order to justify its position, the AER was driven to re-writing cl 6.4.3(a)(6) and cl 6.4.3(b)(6) in order to remove the constraints imposed upon its approach by the definition of "previous *regulatory control period"* so as to make clear that the particular clauses contemplated the carrying over into the current *regulatory control period* negative carryover resulting from performance in the 2001–2005 regulatory period.

615 The fact that the AER had to resort to rewriting the clause, in our view, confirms that, upon the correct interpretation of the clause as it is drafted, it does not authorise a carryover into the current *regulatory control period* of these negative amounts in the case of Powercor.

616 The consequence of the conclusions which we have expressed at [613]–[615] above is that the AER had no power to do that which it did. Its decision must be set aside.

617 The AER has raised in its Written Submissions (at pars 112–129) the proposition that a holding by this Tribunal that the AER did not have power to carryover into the current *regulatory control period* the negative amounts which it purported to carryover from the 2001–2005 regulatory period, might have consequences for decisions made in respect of other DNSPs upon the same basis as the decision which we have made in respect of Powercor.

618 The Tribunal proposes to reserve for further consideration the consequences of its decision insofar as other DNSPs are concerned. As was the case with Issue 3, the Tribunal will invite the parties to make submissions in respect of those consequences.

619 In light of the conclusions to which we have come in respect of this issue, it is not necessary for us to consider discretionary factors.

ISSUE 16—VEGETATION MANAGEMENT OPEX STEP CHANGE (CITIPOWER AND POWERCOR)

Introduction

620 This issue concerns both CitiPower and Powercor.

621 The step change involved in this issue arises from changes made in regulations made under the Safety Act. In particular, the changes that were made to those regulations concerned electrical line clearances. Until 29 June 2010, the regulations were those contained in the regulations made in 2005. Those regulations contained certain exceptions and various other provisions which were less onerous in terms of the work programs required to be carried out by the DNSPs. The 2010 regulations did not carry over those exemptions. In addition, there was a standalone exemption granted by ESV to the DNSPs in respect of the manner in which they are obliged to deal with vegetation management in the HBRA. That standalone exemption did not continue beyond the making of the 2010 amendments to the regulations made under the Safety Act.

622 Under cl 9 of the *Electricity Safety (Electric Line Clearance) Regulations 2005* (**the 2005 clearance regulations**) in force prior to the 2010 amendments, certain clearance spaces around aerial bundled cables and insulated cables in all areas were stipulated for by reference to tables and diagrams forming part of the schedule to those regulations. Some relief from the requirements of cl 9.1 was afforded to DNSPs through the exceptions set out in cl 9.3. Clause 9.3 provided:

> 9.3 If the responsible person complies with clause 12, the requirements of clause 9.1 do 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.

623 Clause 12 provided an exception in the event that appropriate annual risk assessments were carried out at the behest of the relevant DNSPs. In general terms, the effect of this exception was that the DNSPs could allow light vegetation into the mandated clearance space, so long as they were not likely to abrade the cable. One of the areas of present controversy concerns insulated cable, that is to say, cables that pass between a pole and, ordinarily, a house or other building. There are many thousands of such cables both in metropolitan and regional areas.

624 The 2010 regulations removed the opportunity for DNSPs to avoid the strict consequences of applying cl 9.1 of the 2005 clearance regulations.

625 The second substantial change concerned spans between poles which exceeded 100 metres in length. In respect of those spans, the minimum clearance space must be

extended by an additional distance to allow for sag and sway of the conductors. Further, an additional distance must be added to the minimum clearance space to allow for regrowth during the period between cutting times. Table 2 in the *Electricity Safety (Electric Line Clearance) Regulations 2010* (**the 2010 clearance regulations**), specified minimum clearance spaces are laid down for spans exceeding 100 metres.

626 The third significant change was the removal of a specific exemption granted to Powercor under reg 10 of the 2005 clearance regulations in respect of HBRA. That exemption had provided:

> **1. Hazardous Bushfire Risk Areas**
>
> Powercor is exempted from the requirement to maintain a clearance space in accordance with clause 2.1 of the [2005 Clearance Regulations] provided that Powercor achieves the minimum clearance space requirements specified in Tables 9.3 and 11.1 of [those Regulations] 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) 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.

627 That exemption was not continued in the 2010 clearance regulations. It was not continued in any ongoing regulatory legislation or instrument after the making of the 2010 clearance regulations.

628 The fundamental difference of opinion in respect of this issue between the AER and Powercor, (and, to a lesser extent, CitiPower) concerns the unit rates applied by the AER. The AER picked up the unit rates propounded by other DNSPs, being lower than those put forward by CitiPower and Powercor, and adopted those rates to the larger span volumes, in particular. The approach taken by the AER did not accommodate the clearance plans actually put together by CitiPower and Powercor and approved by ESV.

629 Citipower and Powercor argued that, in adopting the rates which it did, the AER committed errors of fact, wrongly exercised a discretion and acted unreasonably in all the circumstances. The AER submitted that it did its best with the information which had been provided by CitiPower and Powercor.

The Contentions made by CitiPower and Powercor

630 The clearance work which the DNSPs are required to carry out around their poles, wires and other infrastructure is carried out by subcontractors. That is to say, it is carried out by expert clearance contractors. The Tribunal was informed that, in Victoria, effectively there are only two such contractors. CitiPower and Powercor use the same contractor. Other distributors use a different contractor.

631 Step changes within a *regulatory control period* are the means by which an allowance for incremental costs arising from (*inter alia*) changes in regulatory obligations or changes in the DNSP's operating environment from the base year are provided for.

632 The expert retained by the AER (Nuttall Consulting) made a fundamental error in failing to appreciate the idiosyncrasies of the Powercor (and, to a lesser extent, CitiPower) network. It applied general conclusions in order to derive averages across the whole of the State by reference to (*inter alia*) the circumstances of other DNSPs but failed to appreciate that the Powercor network was to a large extent different from the other networks.

633 In general terms, the costs of a given vegetation work program are the product of the number of spans to be dealt with in that work program and the unit rate (per span), or the average cost per span, for actioning those spans. The nature of the work required to be carried out on any span, and therefore the volume of work activity per span, may differ between work programs, with the result that different unit rates are used in costing different work programs.

634 The revised regulatory proposals lodged by CitiPower and Powercor took into account the commencement of the 2010 clearance regulations. Accordingly, CitiPower and Powercor included in their revised regulatory proposals operating expenditure step change amounts to account for the increase in costs estimated to result from these changes.

635 In the case of CitiPower, it does not have any HBRA or spans exceeding 100 metres. Therefore, two of the significant regulatory changes do not impact upon CitiPower.

636 CitiPower and Powercor ordinarily engage an independent, third party vegetation management contractor, Vemco Pty Ltd (**VEMCO**), to undertake vegetation clearance on

their networks in accordance with the requirements of the regulations applicable from time to time. VEMCO has provided vegetation management services to CitiPower and Powercor since 1997.

637 For the purposes of proposing their step change amounts in respect of the regulatory changes referred to at [621]–[627] above, CitiPower and Powercor obtained cost estimates from VEMCO. Those estimates were set out in a letter to CitiPower and Powercor from VEMCO dated 13 July 2010. That letter was provided to the AER.

638 In that letter, the author said:

> We have considered the cost impact of each of the key regulatory changes identified in the advice from DLA Phillips Fox and we have identified the below key regulatory changes in the 2010 Regulations as having a major cost impact on PAL/CP. Based on our analysis of the increased workload to comply with the changes to the Regulations the following costs increases, above the 2009 actual costs, will apply over the five years from January 2011 to end December 2015.

639 Immediately following that paragraph, the author set out a table in the following terms:

#	Nature of Change	Cost for Powercor Network	Cost for CitiPower Network
1	Removal of Exemption from compliance with clearance space requirements in hazardous bushfire risk areas (**HBRA**)	**$28,800k**	**$0k**
2	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 Code (clause 2(3) of the 2010 Code).	**$6,368k**	**$280k**
3	New requirement that the cutting or removal of habitat trees must be undertaken outside of breeding season wherever practicable, and if not practicable translocation of fauna must be undertaken (clause 4 of the 2010 Code).	**$500k**	**$0k**
4	Changes to notification and consultation requirements (clause 5 of the 2010 Code).	**-$8k**	**-$5k**
5	New requirement to cut trees within 60 days of notifying affected persons (clause 5 of the 2010 Code).	**$150k**	**$50k**

#	Nature of Change	Cost for Powercor Network	Cost for CitiPower Network
6	Omission of clauses 9.2.1 and 9.2.2 of the 2005 Code which allowed light vegetation/foliage to enter the clearance space and omission of clause 9.3 which allowed within the clearance space branches exceeding 130 millimetres that were more than 300 millimetres from an aerial bundled cable or insulated cable – lines from pole to pole.	**$14,481k**	**$1,545k**
7	Omission of clauses 9.2.1 and 9.2.2 of the 2005 Code which allowed light vegetation/foliage to enter the clearance space and omission of clause 9.3 which allowed within the clearance space branches exceeding 130 millimetres that were more than 300 millimetres from an aerial bundled cable or insulated cable – service lines from the pole to the building.	**$20,996k**	**$13,558k**
8	Removal of allowance for reduced clearances in LBRA for powerlines of 22,000 volts or less and powerlines of 566,000 volts by omission of clauses 10(b), 10(c) and 12 of the 2005 Code.	**$9,405k**	**$3,366k**
9	Removal of allowance for overhang in HBRA by omission of clause 11.2 of the 2005 Code.	**$450k**	**$0k**
10	Table 2 of the 2010 Code requires a larger clearance space for spans exceeding 100 metres than Table 10.1 of the 2005 Code.	**$7,300k**	**$0k**

We note that in addition to the above costs of complying with the 2010 Regulations, the following costs above 2009 actual costs will apply during the period January 2011 to end December 2015 in respect of PAL/CP's program of achieving compliance with the clearance space requirements in low bushfire risk areas.

#	Nature of Activity	Cost for Powercor Network	Cost for CitiPower Network
1	Costs of achieving compliance with clearance space requirements in low bushfire risk areas (**LBRA**).	**$3,250k**	**$450k**

640 CitiPower and Powercor carried forward the estimates given to them by VEMCO into their revised regulatory proposals.

641 To facilitate a review by ESV (at the request of the AER) of the volume and number of spans to be actioned in 2011–2015 *regulatory control period* as a result of the changes effected by the 2010 clearance regulations, the AER and ESV requested further and more detailed information from the DNSPs regarding the volume or number of spans to be actioned by them under the 2010 clearance regulations. In response to that request, CitiPower and

Powercor obtained and provided to the AER a statement dated 30 August 2010 made by Mr Joyce, the Managing Director of VEMCO.

642 CitiPower and Powercor placed great reliance before the Tribunal on this statement. The statement is slightly more than 40 pages in length and comprises 226 paragraphs. Mr Joyce is familiar with the networks of both CitiPower and Powercor and described those networks in some detail. He also made clear in his statement that much of the work of clearing would be done by subcontractors retained by VEMCO. The essence of the material conveyed by Mr Joyce is contained in pars 32–39 of his statement which are in the following terms:

> **Vegetation management costs**
>
> 32 Vegetation management costs for any given work program are generally a product of the number of spans to be actioned in that work program and the unit rate (per span), or average cost per span, for actioning those spans.
>
> 33 In costing the changes as between the 2005 Regulations and Code and the 2010 Regulations and Code, I assumed that the various work programs required to address compliance with those changes would be implemented as part of the cyclic inspection and clearance programs that will be carried out by Powercor and CitiPower under the 2010 Code.
>
> 34 The nature of the work required to be carried out on a span and therefore the volume of work activity per span may differ between work programs, with the result that different unit rates are used in costing different work programs. In this case, the nature of the change between the 2005 Regulations and Code and the 2010 Regulations and Code will affect the nature and volume of the work per span required to address that change. As a result, the unit rates per span vary across the different changes between the 2005 Regulations and Code and the 2010 Regulations and Code.
>
> 35 VEMCO determines the unit rates per span for any given work program based on a number of factors, including:
>
> (a) the cutting workload per span associated with the work program including in particular:
>
> (i) the number of trees to be actioned per span in the work program; and
>
> (ii) the targeted clearance distances and the resultant aggressiveness of the cutting required in the work program;
>
> (b) the inspection of spans required as part of the work program (as it is common to recover the costs of these inspections through the unit rate per span applied to the number of spans to be actioned in the work program);
>
> (c) the historical costs of that cutting workload per span and those inspections;
>
> (d) the expected future number of spans to be actioned in the work program to which the unit rate applies and in other work programs or

activities (as this will determine the demand over which common costs, such as the costs of travel to and from the site and management costs, may be spread/recovered and, thus, the amount of these costs reflected in the unit rate for the work program);

(e) the costs of travel to and from the site;

(f) site access costs;

(g) traffic control costs;

(h) clean up requirements for the work program and the resultant clean up costs;

(i) weather impacts (for example, rain and total fire bans);

(j) the notification and consultation costs expected to be associated with the work program;

(k) customer requirements expected to be associated with the work program and the resultant costs of complying with those requirements;

(l) the composition of the crew(s) required for the work program – including the type of crew expertise required to undertake the work and the cost of that crew make up per hour;

(m) enterprise bargaining agreements;

(n) machinery capital and running costs;

(o) the productivity of crews;

(p) the management costs associated with the work program; and

(q) the costs of any auditing required as part of the work program.

36 These factors differ for the different changes between the 2005 Code and the 2010 Code and as between LBRA and HBRA and the CitiPower and Powercor networks. This is because the work per span required to be undertaken differs depending on the relevant change, whether the cutting or removal of the trees required by that change is in LBRA or HBRA and whether the cutting or removal required by that change is in the CitiPower or Powercor network. As a result, in costing the impact of the changes between the 2005 Code and the 2010 Code for CitiPower and Powercor I used different unit rates for different changes.

37 With the exception only of the estimation of the incremental costs due to the removal of the exemption from compliance with the requirements of the 2005 Code in HBRA granted to Powercor by ESV on 21 December 2005 (**HBRA Exemption**), in estimating the incremental cost of any given change as between the 2005 Regulations and Code and the 2010 Regulations and Code I estimated the number of spans that will require vegetation management activities in order to comply with that change. In some cases, the spans would have still required action in the absence of the change (i.e., in order to comply with the 2005 Regulations and Code), but the change under the 2010 Regulations and Code necessitates that additional work be carried out in actioning the spans. The unit rate I applied to the estimated number of spans requiring vegetation management activities as a result of the change reflects only the cost per span of those additional work activities necessitated by the change. This ensured that only the cost of the additional work activities necessitated by the change between the 2005 Regulations and Code and the 2010 Regulations and Code are costed.

> 38 In estimating the incremental costs due to the removal of the HBRA Exemption, the method I adopted differs from that described in the preceding paragraph but it nonetheless ensures that I isolated the incremental cost due to the removal of the HBRA Exemption. This method is described in detail below.
>
> 39 I describe in detail below the impact of the key changes for Powercor and CitiPower identified in paragraphs 10 and 14 above and my methodology for calculating the incremental costs of those key changes.

643 At par 77 of his statement, Mr Joyce set out various unit costs which he had used in formulating his cost estimate conveyed to CitiPower and Powercor by his letter dated 13 July 2010. He did not, however, explain in par 77 (or anywhere else in his statement) precisely how he had derived those unit rates. At par 79 of his statement, he provided a summary of the total cost position in which he compared the costs of clearing in accordance with the 2010 clearance regulations and the costs of doing so without the impact of those regulations. He also made some general remarks concerning the frequency with which inspections will be required in the future.

644 In oral submissions made to the Tribunal, Senior Counsel for CitiPower and Powercor spent some considerable time going through the statement made by Mr Joyce in an endeavour to persuade the Tribunal that the statement was very detailed and provided all the reasonable information that the AER could have required in order to accept the step change amounts included in the revised regulatory proposal of CitiPower and Powercor.

645 In the final decision, the AER did not accept the step change amounts proposed by CitiPower and Powercor. It concluded that:

(a) The unit rates estimated by Mr Joyce of VEMCO and proposed by CitiPower and Powercor did not reasonably reflect the efficient and prudent unit rates of complying with the relevant changes effected by the 2010 clearance regulations; and

(b) The efficient and prudent step change amounts for CitiPower and Powercor were those estimated by applying unit rates based on those proposed by other DNSPs to the volumes estimated by VEMCO and proposed by CityPower and Powercor.

646 The AER had asked the ESV to carry out an assessment of the volume of work proposed by VEMCO. The ESV reported to the AER that the volume of work proposed by

VEMCO as a result of the changes effected by the 2010 clearance regulations was reasonable.

647 The AER, therefore, ultimately reached its conclusion on the basis that it was not satisfied with the unit rates which VEMCO had proposed to CitiPower and Powercor. Its dissatisfaction on this point was based upon the findings of Nuttall Consulting. Nuttall Consulting had been retained by the AER to evaluate those rates.

648 CitiPower and Powercor contend that the evaluation conducted by Nuttall Consulting was defective because it placed too much emphasis on common features across all networks and, in particular, on unit costs on an average basis undertaken by other networks without paying due regard to the idiosyncrasies of the CitiPower (and, in particular) the Powercor networks.

649 Nuttall Consulting took the approach which it did because it came to the view that:

(a) CitiPower and Powercor had not provided sufficient information to support their cost estimates;

(b) The supporting information provided by, and unit rates of, the other DNSPs were highly consistent (although inconsistent with those supplied by CitiPower and Powercor);

(c) The VEMCO unit rates underpinning CitiPower's and Powercor's step change amounts were considerably higher than the unit rates proposed by the other DNSPs; and

(d) Nuttall Consulting could not deduce any legitimate reasons for these differences.

650 For these reasons, the AER substituted its own estimates for the step change amounts propounded by CitiPower and Powercor.

651 The errors to which CitiPower and Powercor point are the following:

(a) The AER failed to afford to each of CitiPower and Powercor procedural fairness in the regulatory process;

(b) The AER erred in concluding that CitiPower and Powercor had not provided sufficient detail and sufficient information to support their proposed step change amounts;

(c) The AER placed undue weight on the findings of Nuttall Consulting and insufficient weight on the material provided by Mr Joyce;

(d) The AER failed to take due account of the fact that the other DNSPs were all serviced by one clearance contractor whereas CitiPower and Powercor were serviced by the only other available clearance contractor; and

(e) The AER placed far too much weight on the unit rates propounded by the other DNSPs.

652 CitiPower and Powercor devoted a great deal of time and effort, both in their written and oral submissions, in attempting to make good the errors which we have summarised at [651] above. Accompanying those submissions were various schedules which Senior Counsel deployed in aid of his oral submissions.

653 In very broad terms, those schedules were designed to demonstrate the following:

(a) In relation to HBRA, compared with all of the other DNSPs, Powercor’s less frequent cutting involves more aggressive cutting, which is more costly per span cut than more frequent light cutting. This illustrates the need for the AER, when comparing unit rates of one DNSP with one or more of the other DNSPs, to be careful to ensure that appropriate consideration is given to the differences between the networks and the work programs in place for achieving the clearance requirements according to the relevant regulations.

(b) Insofar as the insulated service line changes were concerned, it is apparent that there were vast differences in the frequency of cutting in SP AusNet’s network compared with Powercor’s network. Nuttall Consulting had placed considerable weight on SP AusNet’s rates. In addition, there were substantial differences between the inclusions in the rate as between CitiPower and UED/JEN. The costliest lines, for example, were not in the unit rate because aspects of the costs were dealt with as capital (rather than opex). Furthermore, the AER did not make allowance for inspection costs in applying the unit rates of other DNSPs.

(c) In respect of the low bushfire risk area (**LBRA**) spans exceeding 100 metres, Powercor submitted that the vegetation characteristics of those spans as between the networks were vastly different. The use of other DNSPs' unit rates in respect of those items did not provide a proper comparison.

654 The procedural fairness complaint is a simple one: CitiPower and Powercor complain that the AER should have told them that it was contemplating evaluating the efficiency and prudence of unit rates calculated by VEMCO by comparing them with unit rates put forward by other DNSPs. It did not do this. Second, it should have provided to CitiPower and Powercor the unit rates which it had in mind benchmarking so that CitiPower and Powercor could comment on those rates. It did not do that. Third, the denial to CitiPower and Powercor of the opportunity to comment on the rates propounded by the other DNSPs produced a serious injustice because Nuttall Consulting and the AER placed far too much store in the utility of using the other DNSPs' rates as a comparator.

The AER's Submissions

655 In its draft decision, the AER expressed dissatisfaction with the forecast opex provided by each of the DNSPs. It also made reference to step changes. Appendix 1 to the AER's draft decision described the AER's approach to benchmarking. In that Appendix, the AER said that, with assistance from its consultants, it had undertaken trend analysis, bottom up benchmarking, ratio analysis and reviews of policies and procedures to compare the efficiency of the opex and capex forecasts proposed by the DNSPs.

656 In Appendix L to its draft decision, the AER set out its analysis of the DNSPs proposed step changes. The AER foreshadowed an expectation on its part that more precise forecasts in respect of the step changes likely to be required as a response to the 2010 clearance regulations would be known by the time the revised regulatory proposals were submitted to it.

657 After publishing its draft decision, the AER looked carefully at Annexure MJ-7 to Mr Joyce's statement and the calculations contained in the spreadsheet forming part of that Annexure. The spreadsheet only contained calculations in relation to the removal of the HBRA exemption. It did not contain calculations in respect of any other proposed step changes as a result of the 2010 clearance regulations coming into force. The unit rates shown

in the spreadsheet were final numbers without any breakdown or detailed information about how they had been derived. That shortcoming was not ameliorated by the text of the statement.

658 Nuttall Consulting benchmarked CitiPower's and Powercor's step change amounts and formed the view that they were excessive. The AER said in the final decision that it had assessed the step changes solely against the opex criteria and the opex factors according to cl 6.5.6 of the NER in a manner which was consistent with the NEO and which took into account the RPP. It explained its reasoning processes in Appendix H and Appendix L to the final decision.

659 The AER submitted that its decision was perfectly justifiable given the shortcomings in the information provided by CitiPower and Powercor.

Decision

660 Despite the volume of words and the many pages devoted to the exercise, the information provided by CitiPower and Powercor via Mr Joyce's cost estimates and statement was at a general and "high level". A close examination of that information reveals that very little information about the build up of the unit rates relied upon by Mr Joyce was provided by CitiPower or Powercor or Mr Joyce. Virtually no information about the rates to be charged to VEMCO by its subcontractors was provided to the AER. Furthermore, no comparison between the rates proposed in the revised regulatory proposals and those incurred by the CitiPower and Powercor businesses in the 2009 calendar year was undertaken. As the AER pointed out, answers to the following questions would, at a minimum, have assisted the AER to accept the step change amounts proposed. These questions are:

- How many workers are in each crew (both cutting and clean up)?
- What are their hourly contract rates?
- What amount of time has been allocated for those crews per span?
- How many workers are involved in inspections?
- What are their hourly contract rates?
- What amount of time has been allocated for those inspections per span?

- What resources are required for notification and consultation, data capture, subcontractor resource management, auditing and quality control?
- How is the unit rate of $182.00 per crew broken down into the components generally listed in Mr Joyce's statement?

661 At par 35 of his statement, Mr Joyce lists a number of matters but does not relate those matters to the particular exigencies of the circumstances and network programs of each of CitiPower and Powercor. He made no effort at all to connect up the various matters listed in par 35 to the unit rates contained in his spreadsheet by, for example, breaking out those unit rates by reference to the various matters listed.

662 Furthermore, Mr Joyce was working on estimates. There was no evidence either before the AER or before the Tribunal, one way or the other, as to whether VEMCO had entered into a contract with either CitiPower or Powercor to do the work contemplated. There was, therefore, no firmness about the estimate beyond Mr Joyce's assertion that the estimates were reasonable.

663 The AER was entitled to be suspicious of the quantum of the step change amounts claimed by each of CitiPower and Powercor given the shortcomings in the information provided and the significant increase over the 2009 base year. Furthermore, it was entitled to benchmark those rates against information provided by the other DNSPs.

664 In our view, CitiPower and Powercor had ample opportunity to provide greater assurance to the AER concerning the step change amounts which they had claimed. They must be taken to have understood that the AER would wish to look at the rates which underpinned those amounts carefully, would wish to benchmark them against the other DNSPs' rates and would wish to cross-check them as against expenditure in prior periods.

665 For the reasons which we have explained at [660]–[664] above, we think that the AER was justified in not being satisfied with the information which had been provided to it by CitiPower and Powercor. The build-up of the unit rates relied upon by Mr Joyce in formulating his cost estimates should have been revealed to the AER so that a careful assessment of those estimates could have been undertaken by the AER and its consultants.

666 On the other hand, the assessment made by Nuttall Consulting failed to pay proper regard to the differences between Powercor's network and those of the other DNSPs and failed to take proper account of the differences between the work programs which had been put in place by Powercor, in particular, and those which the other DNSPs proposed to undertake. After all, the work programs which Powercor had put in place had been assessed as reasonable by ESV, at the behest of the AER. ESV had concluded that the Powercor work programs constituted a reasonable response to the new regulatory environment created by the Victorian Government as a result of the Black Saturday bushfires.

667 The AER was justified in not being satisfied with the VEMCO costings. However, its assessment of the costs of Powercor's work programs was unreasonable.

668 In those circumstances, we propose to remit this issue to the AER. We think that CitiPower and Powercor should be given a further opportunity to justify the VEMCO estimates and that the AER should then reconsider its decision on this issue in light of the information then available to it.

669 Given that there is to be a remitter of the final determinations of both CitiPower and Powercor, it is not necessary to consider the procedural fairness grounds raised by those corporations in relation to this issue.

670 There will be orders accordingly.

SUMMARY OF CONCLUSIONS

671 The conclusions to which we have come in these Reasons for Decision may be summarised as follows:

Issue 1—Public Lighting Issues	SGC failed to make out any of the grounds of review that were the subject of leave granted by the Tribunal to SGC pursuant to s 71B of the NEL. The decisions made by the AER in respect of the public lighting issues are affirmed.
Issue 2—UED Opex and Internal and Related Party Costs	UED has failed to make out its ground of review concerning the AER's assessment of a component of its forecase opex (viz its internal

and related party costs) for the base year of the regulatory control period.

The decisions made by the AER in respect of that matter are confirmed.

Issue 3—Closeout of the ESCV's "S" Factor Scheme

The AER erred by applying in the distribution determination for UED the methodology which it developed for closing out the ESCV "S" Factor Scheme because it did not have power to apply that methodology. The distribution determination in respect of UED must be remitted to the AER so that it can remake the distribution determination in respect of UED upon a basis which does not involve the application of its methodology for closing out the ESCV "S" Factor Scheme.

There will be liberty to apply to the AER and to each of the other DNSPs in respect of the consequences of this decision.

Issue 4—Establishment of the Regulatory Asset Base (Capitalised Related Party Margins)

The Minister failed to make out any of the grounds of review that were the subject of leave granted by the Tribunal to him pursuant to s 71B of the NER in respect of this issue.

The decisions made by the AER in respect of the Regulatory Asset Base (Capitalised Related Party Margins) issue are affirmed.

Issue 5—Establishing the Regulatory Asset Base as at 1 January 2016 (Depreciation)

The Minister failed to make out any of the grounds of review that were the subject of leave granted by the Tribunal to him pursuant to s 71B of the NER in respect of this issue.

The decisions made by the AER in respect of the Regulatory Asset Base (Depreciation) issue are affirmed.

Issue 6—Indexation of the Regulatory Asset Base for Inflation

The AER erred in its methodology for indexing the regulatory asset base for inflation by using as a starting point for the period in respect of which indexation is to occur the date "*September 2003*". It should have used as a starting point for that exercise the date *"1 July 2004"* and also used, on that basis, the values of the regulatory asset base of each of the DNSPs specified in the table forming part of cl S6.2.1(c)(1) of the NER.

The distribution determination in respect of JEN must be remitted to the AER so that it can remake the distribution determination in respect of JEN upon a basis which conforms to the requirements of the NER (including the particular matters addressed in the immediately preceding paragraph).

There will be liberty to apply to the AER and to each of the other DNSPs in respect of the consequences of this decision.

Issue 7—Debt Risk Premium (Annualisation and Methodology)

The AER erred by having regard to the APT bond when determining JEN's debt risk premium.

The distribution determination in respect of JEN will be varied by deleting the figure "3.70%" for the DRP in Table 14 of that distribution determination and substituting therefor the figure "4.34%".

The AER also erred in annualising the DRP in all of the distribution determinations in the respects specified in par 11 and par 12 of Attachment "C" to these Reasons.

The remaining distribution determinations will be varied by:

(a) replacing the figure "3.74%" for the DRP in Table 13 of the distribution determination in respect of UED with the figure "3.89%".

(b) replacing the figure "4.05%" for the DRP in Table 14 of the distribution determination in respect of SP AusNet with the figure of "4.22%".

(c) replacing the figure of "3.74%" for the DRP in Table 14 of the distribution determination for each of CitiPower and Powercor with the figure of "3.89%".

Each distribution determination is also otherwise to be varied as may be required in order to give effect to the variations in DRP values specified above, including, in particular, the resultant recalculation of the rate of return (or WACC), return on capital, annual revenue requirements and "X" factors for standard control services and the affected control mechanisms for alternative control services specified in each of those distribution determinations.

Issue 8—JEN Capital Expenditure (Broadmeadows Relocation Project)	The AER erred in its decision to substitute zero capital expenditure for 2011 for the Broadmeadows project in place of the direct costs amount proposed by JEN. The distribution determination in respect of JEN is to be varied by including in the forecast capital allowance for JEN for the 2011–2015 regulatory control period an allowance in the amount confidentially agreed between the AER and JEN in respect of the Broadmeadows project.
Issue 9—Disallowance of Certain Enterprise Support Function Cost Centres (JEN)	The AER erred when it disallowed certain Enterprise Support Function Costs in the forecast opex for JEN for the 2011–2015 regulatory control period. This distribution determination in respect of JEN will be varied so that the amounts claimed by JEN in its revised regulatory proposal in the enterprise support function costs centres described as: (a) Energy Investment; (b) Financial Strategy; and (c) Investment Analysis be allowed in accordance with these Reasons
Issue 10—Gamma	The AER erred when, in respect of the value of gamma, it determined a distribution rate of between 0.7 and 1 and a value of theta of 0.65. The AER should have used the figure of 0.7 for the distribution rate and a value for theta of 0.35. Each of the distribution determinations will be varied by replacing the figure “0.50” as the value for gamma with the figure “0.25” as the value for gamma when used as input in the calculation of the cost of corporate income tax.
Issue 11—Materiality Threshold for Nominated Pass Through Events (SP AusNet)	SP AusNet failed to make out any of the grounds of review that were the subject of leave granted by the Tribunal pursuant to s 71B of the NEL. The decision made by the AER to fix a

	materiality threshold of 1% of the smoothed forecast of the revenue of the regulatory year in which the costs are incurred in respect of insurance pass through events is affirmed.
Issue 12—The Insurance Event Issue (SP AusNet)	See separate confidential Reasons for Decision (*Application by SPI Electricity Pty Limited* [2012] ACompT 2).
Issue 13—Efficiency CarryOver Mechanism (Vegetation Management Opex) (Powercor)	The AER erred by declining to make the ECM adjustments for 2008–2009 proposed by Powercor incurred in achieving compliance with the 2005 clearance regulations. The distribution determination in respect of Powercor will be varied by: (a) replacing the annual revenue requirements for 2011–2015 set out in Table 6 of that distribution determination with annual revenue requirements for 2011–2015 that have been recalculated by excluding therefrom (in addition to the 2001–2005 negative carryover arising under the ORG's 2001–2005 ECM) the 2006–2010 efficiency carryover amounts under the ESCV's 2006–2010 ECM. That determination will also otherwise be varied as required to give effect to this variation, including, in particular, the resultant recalculation of the "X" factors for standard control services specified in that determination.
Issue 14—Victorian Bushfire Royal Commission Nominated Pass Through Event (CitiPower and Powercor)	CitiPower and Powercor have failed to make out any ground of review in respect of the decision made by the AER not to nominate an additional pass through event in respect of the consequences of recommendations made by the Victorian Bushfire Royal Commission. The decision by the AER in this respect is affirmed.
Issue 15—2001–2005 Accrued Negative Carryover (Powercor)	The AER erred when it applied to Powercor's annual revenue requirements for the 2011–2015 regulatory control period an accrued negative carryover from the 2001–2005 regulatory period. It did not have power to apply that carryover to

the current regulatory control period.

The distribution determination in respect of Powercor will be varied by excluding from Powercor's annual revenue requirements for the 2011–2015 regulatory control period the accrued negative efficiency carryover from the 2001–2005 regulatory period.

That determination will also otherwise be varied as required to give effect to this variation, including, in particular, the resultant recalculation of the "X" factors for standard control services specified in that determination.

Issue 16—Vegetation Management Opex Step Change (CitiPower and Powercor)

CitiPower and Powercor have established that, notwithstanding that the AER was justified in not being satisfied that the VEMCO cost estimates met the requirements of the NER in respect of this step change, the substitution of the costings prepared by Nuttall Consulting for those of VEMCO was an incorrect exercise of discretion and unreasonable in the circumstances.

The decision of the AER in respect of this matter will be remitted to the AER to be remade in accordance with the NEL, the NER and these Reasons for Decision.

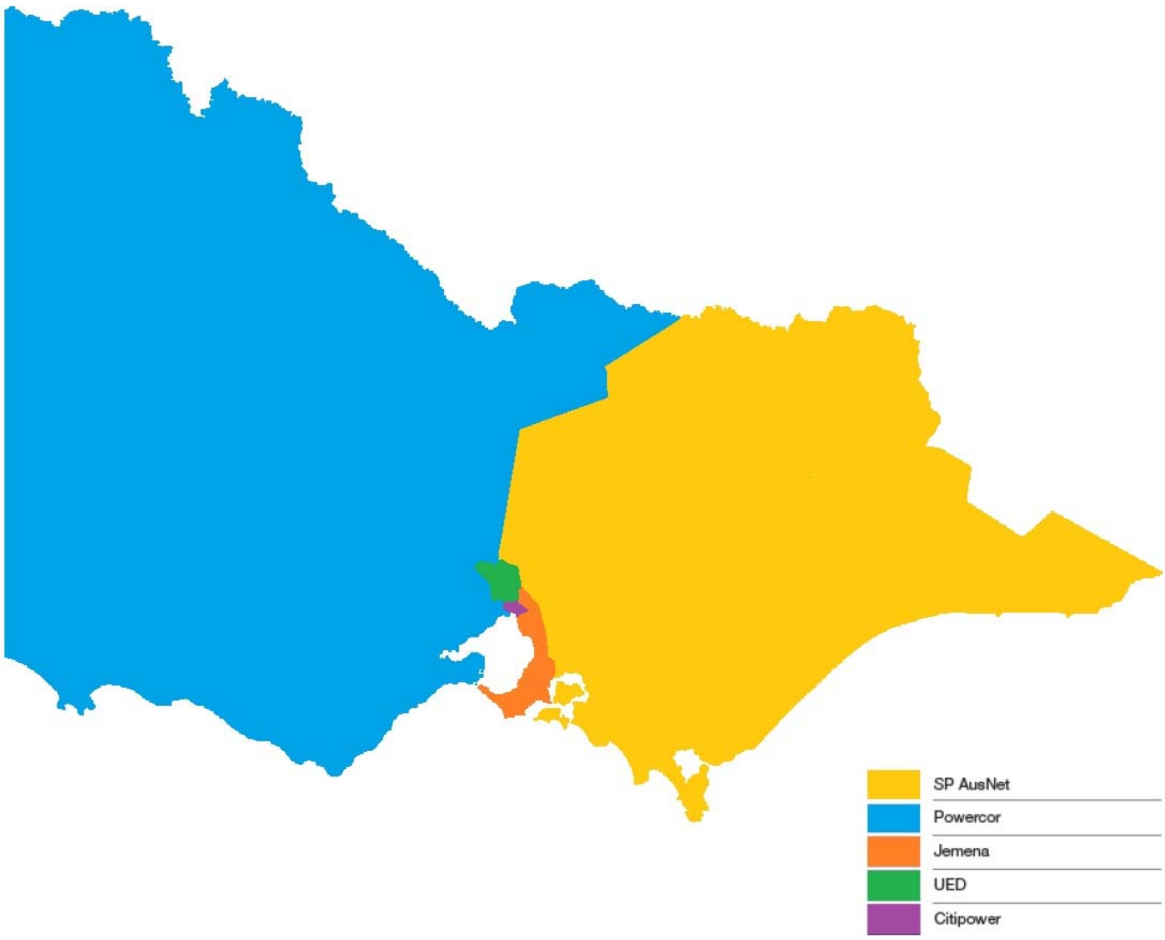
I certify that the preceding six hundred and seventy-one (671) numbered paragraphs are a true copy of the Reasons for Decision herein of the Honourable Justice Foster (Deputy President), Mr G Latta AM and Professor D Round.

Associate: Tanya Hamilton

Dated: 6 January 2012

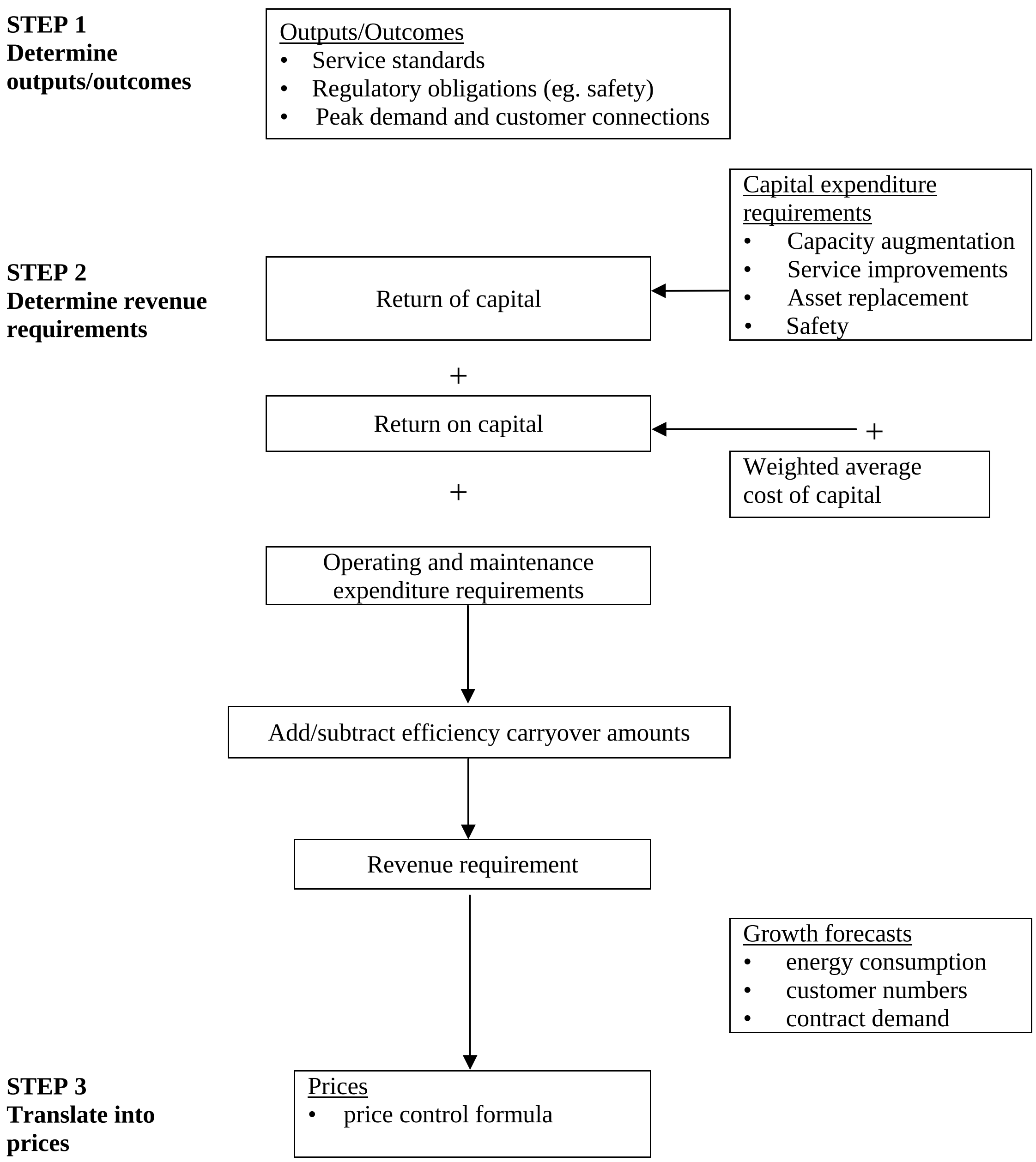
ATTACHMENT "A"

Victorian DNSPs' Distribution Areas



ATTACHMENT “B”

Building blocks to approach to setting the price controls



ATTACHMENT "C"

Commonwealth of Australia

National Electricity (Victoria) Act 2005

In the Australian Competition Tribunal

File Nos. 6, 7, 8, 9 and 10 of 2010

Re	**Applications under s71B(1) of the National Electricity Law for a review of distribution determinations made by the Australian Energy Regulator in relation to CitiPower Pty, Powercor Australia Limited, United Energy Distribution Pty Ltd, SPI Electricity Pty Ltd and Jemena Electricity Networks (Vic) Ltd pursuant to clause 6.11.1 of the National Electricity Rules**
Applicants	**CitiPower Pty, ABN 76 064 651 056 (CitiPower)**
	Powercor Australia Limited, ABN 89 064 651 109 (Powercor Australia)
	United Energy Distribution Pty Ltd (ABN 70 064 651 029) (UED)
	SPI Electricity Pty Ltd (ABN 91 064 235 776) (SPI)
	Jemena Electricity Networks (Vic) Ltd (ACN 064 651 083) (JEN)

JOINT SUBMISSIONS OF THE AUSTRALIAN ENERGY REGULATOR AND THE APPLICANTS IN RELATION TO DRP ANNUALISATION

Filed on behalf of the Applicants and the AER by:		
DLA Piper Australia	DX:	147 Melbourne
Lawyers	Tel:	(03) 9274 5000
140 William Street	Fax:	(03) 9274 5111
Melbourne Vic 3000	Ref:	FCG:NLC:0451021 1110481292

A INTRODUCTION

1 On 19 November 2010, each of UED, SPI, JEN, CitiPower and Powercor Australia (together, **the Applicants**) made applications under section 71B of the National Electricity Law (**Law**) for a review by the Australian Competition Tribunal (**Tribunal**) of the final distribution determinations made by the Australian Energy Regulator (**AER**) in respect of each of the Applicants for 2011-15.[1]

2 One of the grounds for review that was raised by each of the Applicants in their respective applications for review was the AER's decision, in determining the value of the debt risk premium (**DRP**), not to annualise the Bloomberg fair value bond yield data (**DRP annualisation ground**).[2] On 18 February 2011, the Australian Competition Tribunal (**Tribunal**) granted each of the Applicants leave to apply for review in respect of the DRP annualisation ground.[3]

3 The DRP is intended to equate to a commercial cost of debt.[4] The DRP for the regulatory control period is an input parameter to the determination of the rate of return for the regulatory control period.[5] The rate of return (which the National Electricity Rules (**Rules**) require be calculated as a nominal post-tax weighted average cost of capital (**WACC**)) is, in turn, used to calculate the return on capital building block that is a component of the annual revenue requirements for each regulatory year of the period.[6] The higher the value of the DRP, the greater is the return on capital building block included in the annual revenue requirements, *ceteris paribus*.

4 Clause 6.5.2(b) of the Rules provides in respect of the rate of return for the regulatory control period:

> The rate of return for a *Distribution Network Service Provider* for a *regulatory control period* is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the *distribution* business of the provider…

5 Clause 6.5.2(e) of the Rules provides:

> **Meaning of debt risk premium**
>
> (e) The debt risk premium is the premium determined for that *regulatory control period* by the *AER* as 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.

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[1] RB (Core Documents), Vol 1, Tabs 1, 3, 5, 7 and 9.
[2] RB (Core Documents), Vol 1, Tab 1 at [65]-[77], Tab 5 at [49]-[56], Tab 7 at [89]-[96], Tab 9 at [36]-[46], Tab 11 at [7]-[18].
[3] Tribunal Directions dated 18 February 2011, orders 1 to 5.
[4] Draft Decision, p 505 [RB (Decisions & determinations): Vol 1, Tab 2].
[5] Rules, clause 6.5.2(b) [RB (Legislation & authorities): Vol 1, Tab 3, pp 559-60].
[6] Rules, clauses 6.4.3(a)(2) & (b)(2) and 6.5.2(a) [RB (Legislation & authorities): Vol 1, Tab 3, pp 557 and 559].

6 In the AER's final distribution determinations 2011-2015 for each of the Applicants (**Final Determinations**), the AER determined a DRP of 3.74% for CitiPower, Powercor Australia and UED, a DRP of 3.70% for JEN and a DRP of 4.05% for SPI.[7]

B AER'S CALCULATION OF DRP VALUES

7 The DRP determined by the AER was, in each instance, calculated based on the Bloomberg BBB fair value yield curve, which the AER gave 75% weight, and the reported yields on a single bond issued by the Australian Pipeline Trust (**APT**), which the AER gave 25% weight.[8]

8 In determining the DRP for each of the Applicants, the AER applied the WACC model that it prepared and that is contained in the AER's spreadsheet titled 'WACC calculator - final decision.xls' (**AER's WACC model**).[9] The AER's WACC model discloses that, in determining the WACC that is set out in the Final Determinations for each of the Applicants[10], the AER used:

(a) a nominal risk-free rate for the regulatory control period (being another of the input parameters to the determination of the WACC[11]) that had been adjusted to an 'annualised' rate or an 'effective annual yield';[12]

(b) APT bond yields in determining the DRP that had been adjusted in the AER's WACC model into 'annualised' rates or 'effective annual yields'; but

(c) the Bloomberg BBB fair value yield curve in determining the DRP that had not been adjusted in the AER's WACC model into 'annualised' rates or 'effective annual yields', with the consequence that they were 'semi-annual rates', 'expressed on a semi-annual basis' or 'nominal annual rates'.[13]

9 The term 'annualised' is used in the AER's WACC model[14], in expert reports before the Tribunal[15] and in the Applicants' Submissions[16] to denote a bond rate that is calculated so

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[7] Final Determinations, section 3.5.3 (Rate of return) [RB (Decisions & determinations): Vol 2, Tab 8, p 23, Tab 9, p 26, Tab10, p 23, Tab 11, p 23, Tab 12, p 26].
[8] Final Decision, p 514 [RB (Decisions & determinations): Vol 3, Tab 13].
[9] [RB (DRP annualisation): Vol 1, Tab 18. The AER's WACC model is located on the CD behind Tab 15.
[10] Final Determinations, section 3.5.3 (Rate of return) [RB (Decisions & determinations): Vol 2, Tab 8, p 23, Tab 9, p 26, Tab10, p 23, Tab 11, p 23, Tab 12, p 26].
[11] Rules, clause 6.5.2(b) [RB (Legislation & authorities): Vol 1, Tab 3, pp 559-60].
[12] The phrases 'annualised' rate or 'effective annual yield' are used by different authors to describe the same thing. As to their use and meaning, see paragraphs 9 and 10 below.
[13] The phrases 'semi-annual rates' or 'nominal annual rates' are used by different authors to describe the same thing. As to their use and meaning, see paragraphs 9 and 10 below.
[14] AER's WACC model, column AX of the 'Risk free rate & inflation' worksheet (the term 'annualised' is used in cell AX7) and columns C and F of the 'debt Data' worksheet (the term 'annualised' is used in cells C2 and F2) [RB (DRP annualisation): Vol 1, Tab 18]. The AER's WACC model is located on the CD behind Tab 15.
[15] CEG, *Use of the APT bond yield in establishing the NER cost of debt*, October 2010, p 6 at [19] (Attachment 1 to joint Victorian DNSP response to the AER consultation paper *AER draft approach for measuring the debt risk premium for the Victorian Electricity Distribution Determinations* dated 11 October 2010) [RB (DRP annualisation): Vol 1, Tab 13, p 400].

as to take into account the compounding or reinvestment effect of the semi-annual rate over the second half of the year. In the AER's Submissions, it submits that the term 'effective annual yield' should be preferred by the Tribunal to describe such a bond rate.[17] The terms 'semi-annual rates' and 'expressed on a semi-annual basis' are used in expert reports before the Tribunal[18] and in the Applicants' Submissions[19] respectively to denote a bond rate that is not calculated so as to take into account the compounding or reinvestment effect of the semi-annual rate over the second half of the year. In the AER's Submissions, it submits that the term 'nominal annual yield' should be preferred by the Tribunal to describe such a bond rate.[20]

10 Australian corporate bonds generally pay interest twice a year.[21] The value of the semi-annual interest paid is higher than the aggregate amount of interest paid annually (i.e. double the semi-annual interest paid) for the reasons explained above (i.e. due to the compounding or reinvestment effect). Accordingly, the annualised or effective annual yield will be higher than the semi-annual rate or nominal annual yield.

C THE PARTIES' AGREED POSITION ON DRP ANNUALISATION GROUND

11 The Applicants and the AER agree that:

(a) the fair value yields published by Bloomberg and used by the AER in calculating the DRP values for the purposes of its Final Determinations were what the AER describes in its Submissions as 'nominal annual rates' and not what it describes as 'effective annual yields';

(b) in calculating the DRP, the AER did not make the adjustment to convert those fair value yields from what the AER describes in its Submissions as 'nominal annual rates' to what it describes as 'effective annual yields';

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[16] CitiPower and Powercor Australia's *Outline of Joint Submissions in Support of Applications for Review* dated 1 March 2011 at paragraphs 59 to 78 (**Applicants' Submissions**) [RB (Core Documents): Vol 1, Tab 22], which were adopted by the other Applicants in their respective proceedings [RB (Core Documents): Vol 1, Tab 24, [6.1], Tab 17, [67], Tab 19, [180]].
[17] *The Australian Energy Regulator's Outline of Submissions Concerning Debt Risk Premium: "Annualisation Error"* dated 18 March 2011 (**AER's Submissions**) at [11] & [12] [RB (Submissions of the Australian Energy Regulator): Vol 1, Tab 13]; *The Australian Energy Regulator's Outline of Submissions Concerning Debt Risk Premium* dated 18 March 2011 (**AER's JEN Submissions**) at [19] & [20] [RB (Submissions of the Australian Energy Regulator): Vol 1, Tab 14]. The term 'effective annual rate' is also used by PwC to describe in one of its reports what it describes, in another of its reports (referred to in footnote 18 below), as an 'annualised' rate: Letter from Mr Jeff Balchin and Mr Matt Santoro, PwC to Mr Jeremy Rothfield, United Energy Distribution and Multinet Gas, 22 September 2010 (Appendix A to the joint *Submission in response to the Mountain Report on the DRP* dated 24 September 2010), pp 6 and 9 [RB (DRP annualisation): Vol 1, Tab 12, pp 378 and 381].
[18] PwC, *Victorian Distribution Businesses, Methodology to Estimate the Debt Risk Premium*, November 2009, p11 (footnote 4) [RB (DRP annualisation): Vol 1, Tab 3, p 44].
[19] Applicants' Submissions at [72] [RB (Core Documents): Vol 1, Tab 22].
[20] AER's Submissions at [11] & [12] [RB (Submissions of the Australian Energy Regulator): Vol 1, Tab 13]; AER's JEN Submissions at [19] & [20] [RB (Submissions of the Australian Energy Regulator): Vol 1, Tab 14].
[21] AER's Submissions at [9]; AER's JEN Submissions at [17].

(c) what the AER describes in its Submissions as 'effective annual yields' should have been used in estimating the DRP, consistent with the yields for the APT bond used by the AER in estimating the DRP; and

(d) the Applicants have established a ground of review within the meaning of section 71C of the Law[22].

APT bond spread and JEN's averaging period[23]

12 JEN and the AER agree that:

(a) in estimating the DRP over JEN's averaging period the AER gave 25% weight to the spread of the APT bond[24] which was calculated by:

(i) taking the average of the APT bond yields for its first 30 trading days (15 July to 25 August 2010); and

(ii) subtracting that value from the risk free rate over the JEN averaging period (19 April to 31 May 2010).

13 The AER accepts[25] that it should have calculated the spread of the APT bond by:

(b) taking an average of the APT bond yields for the first 30 days of its trading; and

(c) subtracting that value from the risk free rate over the first 30 days of the APT bond trading,

to take into account fluctuations in the risk free rate from the averaging period to the first 30 days of trading.

D DISPOSITION

14 The AER accepts that it is open to the Tribunal to vary the Final Determinations for each of the Applicants pursuant to section 71P of the Law[26] by:[27]

(a) replacing the figure of 3.74% for the DRP in Table 13 of the Final Determination for UED with the figure of 3.89%;

(b) replacing the figure of 4.05% for the DRP in Table 14 of the Final Determination for SPI with the figure of 4.22%;

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[22] RB (Legislation & authorities): Vol 1, Tab 1, p 87.
[23] This issue is unique to JEN as JEN's averaging period differs from those of the other Applicants.
[24] JEN has submitted that it was unreasonable for the AER to use the APT bond yields to estimate the DRP for the JEN averaging period (**JEN DRP methodology ground**). The JEN DRP methodology ground is still to be decided by the Tribunal.
[25] AER's JEN's Submissions at 14.7(a), 15 and 61.1 to 62 [RB (Submissions of the Australian Energy Regulator): Vol 1, Tab 14].
[26] RB (Legislation & authorities): Vol 1, Tab 1, p 91.
[27] AER's Submissions at [16] [RB (Submissions of the Australian Energy Regulator): Vol 1, Tab 13]; AER's JEN Submissions at [76] [RB (Submissions of the Australian Energy Regulator): Vol 1, Tab 14].

(c) replacing the figure of 3.74% for the DRP in Table 14 of the Final Determinations for CitiPower and Powercor Australia with the figure of 3.89%; and

(d) replacing the figure of 3.70% for the DRP in Table 14 of the Final Determination for JEN with a figure of 3.99%, in the event that the Tribunal finds no other error in the AER's Final Decision.[28]

15 The Applicants agree and submit that the Tribunal should make an order or orders:

(a) varying the DRP values specified in the Final Determinations for each of the Applicants in the manner described above; and

(b) otherwise varying the Final Determinations for each of the Applicants as required to give effect to the variation of the DRP values, including in particular the resultant recalculation of the rate of return (or WACC), return on capital, annual revenue requirements and x factors for standard control services and the affected control mechanisms for alternative control services specified in each of those Final Determinations.

Dated: 26 July 2011

Signed on behalf of the AER	Signed on behalf of the Applicants
....	....
Claire Newhouse	Fleur Gibbons
Solicitor for the AER	Solicitor for CitiPower and Powercor Australia

[28] The JEN DRP methodology ground is still to be decided by the Tribunal.

ATTACHMENT "D"

COMMONWEALTH OF AUSTRALIA

National Electricity (Victoria) Act 2005

IN THE AUSTRALIAN COMPETITION TRIBUNAL

File No:	10 of 2010
Re:	Application under section 71B of the National Electricity Law for a review of a distribution determination made by the Australian Energy Regulator in relation to Jemena Electricity Networks (Vic) Ltd pursuant to clause 6.11.1 of Chapter 6 of the National Electricity Rules
Applicant	Jemena Electricity Networks (Vic) Ltd (ACN 064 651 083)
Address of Applicant	321 Ferntree Gully Road Mt Waverley VIC 3149

JOINT SUBMISSIONS OF THE AUSTRALIAN ENERGY REGULATOR AND JEMENA ELECTRICITY NETWORKS (VIC) LTD IN RELATION TO FORECAST CAPITAL EXPENDITURE FOR THE BROADMEADOWS PROJECT

INTRODUCTION

1 On 28 February 2011, Jemena Electricity Networks (Vic) Ltd (**JEN**) filed its written outline of submissions in relation to its grounds for review in these proceedings[1] including, at Part C, JEN's submissions in relation to forecast capital expenditure for its Broadmeadows project.

2 JEN submitted that the Australian Energy Regulator (**AER**) made an error in its decision to substitute zero capital expenditure for 2011 for the Broadmeadows project in place of the $13.4 million (in 2010 dollars, direct cost) for that year proposed by JEN (**Broadmeadows ground of review**).

3 JEN alleged that the AER made an error or errors of fact in the making of the Broadmeadows decision, including because:

(a) the AER had found that the $13.4 million previously allocated to the Broadmeadows relocation project in 2010 remained available to JEN to spend in 2011 as a result of JEN's reduction in expenditure forecast for the project in 2010;

(b) by deferring expenditure from 2010 to 2011, JEN would benefit from both an increased opening regulatory asset base as at 1 January 2011 and a return on and of capital for the period 2011 to 2015.[2]

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[1] JEN Outline of Written Submissions, (Core Documents – Review Book, Tab 24).

[2] JEN Outline of Written Submissions, [9.13] (Core Documents – Review Book, Tab 24).

Filed on behalf of the Applicant and the AER by:

GILBERT + TOBIN	Tel (03) 8656 3300
Lawyers	Fax (03) 8656 3400
Level 39, 120 Collins Street	
MELBOURNE VIC 3000	Ref: CMD:CXE: 1010006 (Catherine Dermody)

4 JEN had also alleged that, further or alternatively, the exercise of the AER's discretion in making the Broadmeadows decision was incorrect and / or unreasonable, including because the AER did not have proper regard, or give sufficient weight to the fact that JEN had only forecast [redacted] in 2010 in relation to the Broadmeadows relocation project.[3]

5 On 18 March 2011, the AER filed an outline of submissions concerning the Broadmeadows project (**the AER Broadmeadows submissions**),[4] in which the AER acknowledged that it is open to the Australian Competition Tribunal (**Tribunal**) to conclude that each of the above alleged grounds for review are made out in these proceedings.[5] The AER:

(a) acknowledged that it is open to the Tribunal to conclude that the AER made one or more errors of fact, which alone or in combination were material to the making of the forecast capital expenditure allowance for the Broadmeadows project;[6]

(b) acknowledged that, on the basis of JEN's revised regulatory proposal submitted to the AER as part of the distribution determination process, there is a justifiable need to undertake a project to consolidate and upgrade the Broadmeadows and Sunshine depots;[7] and

(c) proposed that the Tribunal direct JEN to provide additional information in relation to the forecast expenditure on the Broadmeadows project, including more detailed costing analysis in relation to a number of the options identified in a "feasibility study" report contained at Appendix 8.38 of JEN's revised regulatory proposal.[8]

6 Following the AER's Broadmeadows submissions, JEN wrote to the AER proposing that Broadmeadows ground for review be remitted to the AER for this aspect of the AER's decision to be remade. In this correspondence JEN noted that:

(a) the material submitted by JEN in the distribution determination process was provided to the AER almost a year ago and that during the course of the past year, and as part of its business-as-usual processes, JEN had been conducting, and continues to conduct, further analysis of the options for dealing with the Broadmeadows site and JEN's operational needs; and

(b) some of the analysis referred to in (a) is near completion and some is ongoing and likely to be completed within a three to four month period.

JEN noted that given the passage of time since the submission of the material to the AER relating to the Broadmeadows project and the generation of more up-to-date and detailed analysis, it would be preferable for JEN to provide the AER with

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[3] JEN Outline of Written Submissions, [9.14(a)(ii)], (Core Documents – Review Book, Tab 24).

[4] AER Broadmeadows Submissions, (Confidential – Review Book – Submissions of the Australian Energy Regulator, Tab 2).

[5] AER Broadmeadows Submissions, [9] (Confidential – Review Book – Submissions of the Australian Energy Regulator, Tab 2).

[6] AER Broadmeadows Submissions, [7]-[9] (Confidential – Review Book – Submissions of the Australian Energy Regulator, Tab 2).

[7] AER Broadmeadows Submissions, [32] (Confidential – Review Book – Submissions of the Australian Energy Regulator, Tab 2).

[8] AER Broadmeadows Submissions, [41] (Confidential – Review Book – Submissions of the Australian Energy Regulator, Tab 2).

the up-to-date analysis once it has been finalised to allow the AER to remake this aspect of the decision on the basis of the best information.

7 It is now agreed between the parties that the appropriate course to be adopted in respect of the Broadmeadows ground for review is for the parties to jointly submit to the Tribunal that it is open to the Tribunal to address this matter by varying the final distribution determination for JEN pursuant to section 71P(2)(a) of the NEL by approving a forecast capital allowance of $13.4 million for 2011 (in 2010 dollars, direct cost) in respect of the Broadmeadows project to correct the error.

DISPOSITION

8 The AER accepts that it is open to the Tribunal to vary the reviewable regulatory decision pursuant to section 71P of the Law.[9]

9 If the Tribunal is satisfied that an error has been established, then at the time that the Tribunal makes its determination, JEN and the AER jointly submit that the Tribunal should determine that the decision of the AER under clause 6.5.7 of the National Electricity Rules in respect of the amount of capital expenditure to be allowed for the Broadmeadows project for 2011 – 2015 be varied by approving a forecast capital allowance of $13.4 million for 2011 (in 2010 dollars, direct cost) in respect of the Broadmeadows project.

Dated 21 December 2011

Corrs Chambers Westgarth
Solicitors for the Australian Energy Regulator

Gilbert + Tobin
Solicitors for Jemena Electricity Networks (Vic) Ltd

[9] Review book – Legislation & Authorities, Tab 1, p 91.

ATTACHMENT "E"

COMMONWEALTH OF AUSTRALIA

National Electricity (Victoria) Act 2005

IN THE AUSTRALIAN COMPETITION TRIBUNAL

File No:	6, 7, 8, 9 and 10 of 2010
Re:	Applications under section 71B of the National Electricity Law for a review of distribution determinations made by the Australian Energy Regulator in relation to United Energy Distribution Pty Ltd, SPI Electricity Pty Ltd, CitiPower Pty, Powercor Australia Limited and Jemena Electricity Networks (Vic) Ltd pursuant to clause 6.11.1 of the National Electricity Rules
Applicants	United Energy Distribution Pty Ltd (ABN 70 064 651 029)
	SPI Electricity Pty Ltd (ABN 91 064 235 776)
	CitiPower Pty (ABN 76 064 651 056)
	Powercor Australia Limited (ABN 89 064 651 109)
	Jemena Electricity Networks (Vic) Ltd (ACN 064 651 083)

JOINT SUBMISSIONS OF THE AUSTRALIAN ENERGY REGULATOR AND THE APPLICANTS IN RELATION TO GAMMA

Filed on behalf of the Applicants and the AER by:
GILBERT + TOBIN
Lawyers
Level 39, 120 Collins Street
Melbourne VIC 3000

Tel (03) 8656 3300
Fax (03) 8656 3400

Ref CMD:CXE:1010006 (Catherine Dermody)

1 Introduction

1 On 19 November 2010, each of United Energy Distribution Pty Ltd, SPI Electricity Pty Ltd, CitiPower Pty, Powercor Australia Limited, and Jemena Electricity Networks (Vic) Ltd (together, **the Applicants**) made applications under section 71B of the National Electricity Law (**NEL**) for a review of distribution determinations made by the Australian Energy Regulator (**AER**).

2 One of the grounds for review that was raised by each of the Applicants in their respective applications for review was the AER's decision on the value of gamma (**gamma ground for review**). Gamma represents the assumed utilisation of imputation credits and is an input into the calculation of the cost of corporate income tax, which is a component of the annual revenue requirement – a higher value for gamma reduces the allowance in the annual revenue requirement for the cost of corporate income tax, ceteris paribus, as it is assumed that more of the corporate tax liability is effectively 'recovered' by investors through imputation. Gamma is conventionally calculated as the product of the imputation credit payout ratio (or distribution rate) and the assumed value of distributed imputation credits (theta).

3 In the individual final determinations applying to each of the respective Applicants, and for the reasons set out in the accompanying final decision document (**Final Decision**), the AER had determined a value for gamma of 0.5, based on a distribution rate of between 0.7 and 1 and a value for theta of 0.65.

4 On 18 February 2011, the Australian Competition Tribunal (**Tribunal**) granted each of the Applicants leave to apply for review in respect of the gamma ground for review.

5 Also on 18 February 2011, the Tribunal issued directions for the conduct of these proceedings, including in respect of the gamma ground for review. The direction of the Tribunal requires that the filing of any materials and the substantive hearing in relation to the gamma ground for review be in accordance with further orders to be made following the Tribunal's determination in the merits review proceedings involving Energex, Ergon Energy and ETSA Utilities (ACT file numbers 2, 3 and 4 of 2010, hereafter ***Re Energex***).

6 On 27 June 2011 the Tribunal informed the parties that it would hear the gamma ground for review on 13 July 2011.

2 The decision in Re Energex

7 The *Re Energex* proceedings have now concluded and the Tribunal has published its reasons for decision in relation to gamma.[1] On 19 May 2011, the Tribunal made its final determination for each proceeding giving effect to its reasons for decision. The Tribunal determined that the value for gamma that should be applied in calculating the cost of corporate income tax for each of those businesses is 0.25, based on the product of a distribution rate of 0.7 and a value for theta of 0.35.

8 The Tribunal in *Re Energex* found a number of errors in the AER's decision in respect of gamma for each of Energex, Ergon Energy and ETSA Utilities, including:

(a) in determining a distribution rate of 1, the AER misconstrued the evidence relating to the long-term distribution rate, particularly the Hathaway and Officer (2004)

[1] *Application by Energex Limited (No 2)* [2010] ACompT 7; *Application by Energex Limited (Distribution Ratio (Gamma)) (No 3)* [2010] ACompT 9; and *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9.

study which demonstrates that the long-term distribution rate is around 70 per cent;[2]

(b) in determining a value for theta of 0.65, the AER erroneously took the simple average of a point estimate from a dividend drop-off study (0.57 from Beggs and Skeels (2006)) and an upper bound of 0.74 derived from tax statistics;[3]

(c) the AER misapplied the findings of the Handley and Maheswaran (2008) tax statistics study, by averaging estimates from two separate time periods to arrive at an upper bound for theta of 0.74.[4]

9 In respect of the distribution rate, the Tribunal accepted the AER's submission that there was no empirical data before the Tribunal that was capable of supporting an estimated distribution rate higher than 0.7, and concluded that the distribution rate to be applied in determining the value for gamma is 0.7.[5]

10 In relation to theta, the Tribunal requested that a new 'state-of-the-art' dividend drop-off study be conducted by SFG Consulting based on a methodology that was to be agreed upon by SFG and the AER.[6] Based on the results of the SFG study which was completed in March 2011 (the **2011 SFG study**), the Tribunal concluded that the best estimate of theta is 0.35. The Tribunal found the 2011 SFG study to be the best such study currently available for the purposes of estimating gamma.[7]

11 In coming to its determination, the Tribunal in *Re Energex* had regard to a body of material which largely replicates the body of material that is before this Tribunal, as well as some additional material (prepared after the first decision in *Re Energex*, and which also post-dated the making of the Victorian distribution determination) which is not currently before this Tribunal. Of particular importance was the 2011 SFG study.

12 The 2011 SFG study and the three relevant reasons for decision issued by the Tribunal in *Re Energex* are attached to these submissions for the Tribunal's reference.

13 The decision in *Re Energex* has been adopted by the Tribunal in a recent determination applying to Jemena Gas Networks (NSW) Ltd (**JGN**). In its reasons for decision in the JGN proceedings the Tribunal noted:

> The Tribunal is of the view that...it should follow its recent decision in *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9. It is vitally important that the Tribunal be consistent in its decision making unless special reasons exist which would warrant a departure from earlier cases. If any party is of a different opinion it should forthwith notify the Tribunal.[8]

14 In response to the Tribunal's reasons for decision, JGN indicated that it agreed that the decision in *Re Energex* should be followed and that it would be appropriate for the Tribunal to adopt a value for gamma of 0.25 in the JGN proceedings.[9] The AER indicated

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[2] *Application by Energex Limited (No 2)* [2010] ACompT 7 at [51].

[3] *Application by Energex Limited (No 2)* [2010] ACompT 7 at [91]-[93].

[4] *Application by Energex Limited (No 2)* [2010] ACompT 7 at [95].

[5] *Application by Energex Limited (Distribution Ratio (Gamma)) (No 3)* [2010] ACompT 9.

[6] *Application by Energex Limited (No 2)* [2010] ACompT 7 at [146]-[148].

[7] *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 (12 May 2011), paragraph 29.

[8] *Application by Jemena Gas Networks (NSW) Ltd (No 5)* [2011] ACompT 10, [92]. The Tribunal's determination was made on 30 June 2011 and incorporated a value for gamma of 0.25.

[9] Letter from Gilbert + Tobin (solicitors for JGN) to the Tribunal dated 14 June 2011.

that it accepted that a value of 0.25 from the Tribunal's determination in *Re Energex* should be adopted by the Tribunal for the purposes of the JGN proceedings.[10]

3 The parties' joint position on gamma

Correspondence between the AER and the Applicants

15 On 19 May 2011, following the issuance of final determinations in *Re Energex*, the Applicants wrote to the AER:

(a) indicating that they considered that in the present proceedings the Tribunal should conclude that the appropriate figure for gamma is 0.25, in line with *Re Energex*; and

(b) asking whether the AER agreed that the Tribunal should conclude that the appropriate figure for gamma is 0.25.

16 On 16 June 2011, the AER wrote to the Applicants:

(a) indicating that it proposes to submit to the Tribunal that the AER made an error in arriving at a value for theta of 0.65 in the Final Decision and final determinations for each of the Applicants, as it had in the final determinations for Energex, Ergon Energy and ETSA Utilities;

(b) indicating that it does not intend to submit that the Tribunal in these proceedings should depart from the value of theta of 0.35, as determined in *Re Energex*;

(c) acknowledging that it will be open to the Tribunal to arrive at an overall value of 0.25 for gamma by adopting a value for theta of 0.35 (consistent with *Re Energex*) and a value for the distribution rate within, but near the bottom of, the range established by the AER in the Final Decision (i.e. a value of approximately 0.7, consistent with *Re Energex*); and

(d) indicating that, in view of the above, it accepts that the same relief is appropriate in each of the applications for review ACT 6 to 10 of 2010 and it will not contend that any of the Applicants is precluded from relief by section 71O(2) of the NEL, but that the issue ultimately remains one for the Tribunal to decide.

17 Specifically in relation to 16(a) above, the AER concedes that, by its decision not to depart from the tax-statistics based estimate of theta of 0.74 (derived from the Handley and Maheswaran (2008) tax statistics study[11]), it made a material error of fact and exercised its discretion incorrectly, in that it was illogical to seek to derive an estimate of theta by averaging the redemption rates reported for two different periods in which differing tax and imputation regimes were in force.

Disposal of the gamma ground for review in these proceedings

18 On the basis of the AER's concession of error in its determination of theta in the final determination for each of the Applicants, the parties jointly submit that it is open to the Tribunal to vary each of the determinations under section 71P of the NEL by substituting the correct value for theta and consequently deriving a substitute value for gamma.

[10] Letter from the Australian Government Solicitor (solicitors for the AER) to the Tribunal dated 15 June 2011, [3].

[11] This is the same study referred to in paragraph 8(c) which was relied on by the AER in making the final determinations for Energex, Ergon Energy and ETSA Utilities, as well as in making the final determinations for each of the Applicants.

19 In relation to theta, the AER has conceded that it made an error in making its determination in respect of each of the Applicants. Having regard to the respective positions of the Applicants and the AER as summarised above, if the Tribunal considers that error has been established, it is open to the Tribunal to have regard to new material that would assist in making a determination as to the correct value for theta, including the 2011 SFG Study.[12] As noted above, the Tribunal in *Re Energex* found that on the basis of the 2011 SFG Study, the correct value for theta is 0.35.

20 In relation to the distribution rate, the AER does not concede that it made an error in determining that the distribution rate lies between 0.7 and 1. Whilst it is not necessary for the Tribunal to find error in this aspect of the AER's decision, it will be necessary for the Tribunal to determine a value for gamma that is premised on a value for the distribution rate within the AER's range. It is submitted that, for the reasons articulated by the Tribunal in *Re Energex*, and on the basis of substantially the same body of material that was before that Tribunal in relation to the distribution rate[13], the Tribunal in this matter should determine a value for gamma that is premised on a value of approximately 0.7 for the distribution rate.

21 The Applicants submit that for the same reasons for decision given by the Tribunal in *Re Energex*, the correct value for gamma to be applied in calculating the cost of corporate income tax is 0.25, based on a substitute value for theta of 0.35 and a distribution rate of 0.7. The AER acknowledges that it is open to the Tribunal to adopt a value for gamma of 0.25 and does not oppose the Tribunal making a determination to that effect.

22 The Applicants further submit that no party is precluded from relief by section 71O(2) of the NEL, including because the errors identified by the Tribunal in *Re Energex* were identified by each of the Applicants in submissions to the AER before the final determinations were made.[14] The AER makes no further[15] submission that any of the Applicants are precluded from relief by section 71O(2) of the NEL, save to note that it is a matter for the Tribunal to determine.

23 Accordingly, it is submitted that the Tribunal should vary the final determinations made by the AER in respect of each of the Applicants to substitute a value for gamma of 0.25.

4 Conclusion

24 The parties jointly submit that the Tribunal should be satisfied that:

(a) the AER erred in determining the value for theta to apply to each of the Applicants in its Final Decision and final determinations; and

(b) the appropriate value to be adopted for gamma is 0.25 consistently with the value adopted by the Tribunal in *Re Energex*.

[12] NEL, section 71R(3).

[13] Chiefly the Hathaway and Officer (2004) study referred to at paragraph 8(a) (referred to in the submissions on leave filed by each of the Applicants), which demonstrates that the long-term distribution rate is around 70 per cent.

[14] Section 71O(2) of the NEL provides that a party (other than the AER) to a review under subdivision 1 of division 3A may not raise any matter that was not raised in submissions to the AER before the reviewable regulatory decision was made.

[15] That is, further to the matters noted at paragraphs 31 to 40 of the AER's *Submissions Concerning Leave*, filed on 7 February 2011.

25 The parties submit that the Tribunal should vary the final determinations made in respect of each of the Applicants to incorporate a value for gamma of 0.25.

Dated 11 July 2011

Corrs Chambers Westgarth
Solicitors for the Australian Energy Regulator

Gilbert + Tobin

Gilbert + Tobin
Solicitors for Jemena Electricity Networks (Vic) Ltd (on behalf of the Applicants)

Attachments

Application by Energex Limited (No 2) [2010] ACompT 7

Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9

Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9

SFG, *Dividend drop-off estimate of theta: final report*, 22 March 2011

ATTACHMENT "F"

Commonwealth of Australia

National Electricity (Victoria) Act 2005

In the Australian Competition Tribunal

File No. 9 of 2010

Re	**Applications under s71B(1) of the National Electricity Law for a review of distribution determinations made by the Australian Energy Regulator in relation to Powercor Australia Limited pursuant to clause 6.11.1 of the National Electricity Rules**
Applicant	**Powercor Australia Limited, ABN 89 064 651 109 (Powercor Australia)**

JOINT SUBMISSIONS OF THE AUSTRALIAN ENERGY REGULATOR AND POWERCOR AUSTRALIA IN RELATION TO ECM ADJUSTMENT (VEGETATION MANAGEMENT OPERATING EXPENDITURE) GROUND

INTRODUCTION

1 On 19 November 2010, Powercor Australia made an application under section 71B of the National Electricity Law (**Law**) for a review by the Australian Competition Tribunal (**Tribunal**) of the final distribution determination made by the Australian Energy Regulator (**AER**) in respect of Powercor Australia for 2011-15.[1]

2 One of the grounds for review that was raised by Powercor Australia in its Application was the AER's decision, in calculating the efficiency carryover mechanism (**ECM**) amounts arising in the 2006-10 regulatory period to be included in determining Powercor Australia's annual revenue requirement for each year of the 2011-15 regulatory control period pursuant to clauses 6.4.3(a) and 6.12.1(2) of the National Electricity Rules (**Rules**), not to make an adjustment for certain expenditure necessarily incurred by Powercor Australia in 2008 and 2009 in respect of vegetation management in order to comply with its mandatory statutory line clearance obligations (**ECM adjustment ground**).[2] On 18

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[1] Powercor Australia's *Application for Leave and Application for Review by the Australian Competition Tribunal* dated 19 November 2010 (**Application**) [RB (Core Documents): Vol 1, Tab 7].

[2] Powercor Australia's Application at [51]-[73] [RB (Core Documents): Vol 1, Tab 7].

Filed on behalf of the AER and Powercor Australia by:		
DLA Piper Australia	DX:	147 Melbourne
Lawyers	Tel:	(03) 9274 5000
140 William Street	Fax:	(03) 9274 5111
Melbourne Vic 3000	Ref:	FCG:NLC:0451021 1110444837

February 2011, the Tribunal granted Powercor Australia leave to apply for review in respect of the ECM adjustment ground.[3]

3 Another of the grounds for review that was raised by Powercor Australia in its Application was the AER's decision, in determining Powercor Australia's total and annual revenue requirements for the 2011-15 regulatory control period pursuant to clauses 6.4.3(a) and 6.12.1(2) of the Rules, to bring to account a negative amount said to reflect an accrued negative carryover arising in the 2001-05 period under the ECM of the Office of the Regulator-General (**ORG**) applicable in that period (**2001-05 accrued negative carryover ground**).[4] If the Tribunal determines, consistent with the submissions of Powercor Australia in support of its 2001-05 accrued negative carryover ground, that clause 6.4.3 of the Rules did not give the AER power to apply increments and decrements arising in any previous period including in particular the 2006-10 regulatory period, no carryover amounts arising under the Essential Services Commission's (**ESC**) ECM for 2006-10 can be applied.

4 The background to Powercor Australia's ECM adjustment ground is set out in Section G of CitiPower and Powercor Australia's *Outline of Joint Submissions in Support of Applications for Review* dated 1 March 2011 (**Powercor Australia's Submissions**)[5] at paragraphs 216 to 222 and 281 to 314.

5 For the purposes of calculating the ECM carryover amounts for 2006-10 to be included in Powercor Australia's annual revenue requirements for the 2011-15 regulatory control period, Powercor Australia proposed adjustments to its reported operating expenditure:

(a) in 2008, of $1,496,000 in nominal $2008; and

(b) in 2009, of $4,948,000 in nominal $2009.[6]

6 The amount of these proposed ECM adjustments correlates with the expenditure incurred by Powercor Australia on achieving compliance with the *Electricity Safety (Electric Line Clearance) Regulations 2005* (Vic) (**2005 Line Clearance Regulations**) as modified by the exemption from those Regulations granted to Powercor Australia under regulation 10 in December 2005 (**Exemption**) in respect of low voltage wires in low bushfire risk areas (**LBRA**) in 2008 and 2009 as disclosed in Powercor Australia's Regulatory Accounts.

7 The AER's decision not to make an adjustment of the kind proposed by Powercor Australia in calculating its ECM carryover amounts for 2006-10 to be included in Powercor Australia's annual revenue requirements for the 2011-15 regulatory control period:

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[3] Tribunal Directions dated 18 February 2011, order 4.

[4] Powercor Australia's Application at [35]-[50] [RB (Core Documents): Vol 1, Tab 7].

[5] RB (Core documents): Vol 1, Tab 22.

[6] See the Powercor Australia EBSS model (Attachment 5 to Powercor Australia's Revised Regulatory Proposal), cells P52 and Q52 [RB (ECM adjustment): Vol 2, Tab 30 with the model to be found on the CD under Vol. 1, Tab 1, of the same folder]. The amounts set out in cells P52 and Q52 are in real $2010, and the values are equivalent to the figures set out in paragraph 3 of these submissions.

(a) was made in calculating the other revenue increments and decrements building block that is a component of the annual revenue requirements for each regulatory year of the period in accordance with clauses 6.4.3(a)(6) and (b)(6) of the Rules[7]; and

(b) thus, formed a part of its reasons for its constituent decision under clause 6.12.1(2) of the Rules[8] on Powercor Australia's building block proposal.

8 If the AER had decided to make the adjustment proposed by Powercor Australia in respect of its expenditure necessarily incurred by Powercor Australia in 2008 and 2009 in respect of vegetation management in order to comply with its mandatory statutory line clearance obligations, Powercor Australia's annual revenue requirements for 2011-15 would have been greater *ceteris paribus*.

AER'S DECISION NOT TO MAKE THE ECM ADJUSTMENT PROPOSED BY POWERCOR AUSTRALIA

9 In its *Final decision Victorian electricity distribution network service providers Distribution determination 2011*-15 of 29 October 2010 (**Final Decision**)[9], the AER:

(a) accepted that the additional expenditure incurred by Powercor Australia on vegetation management in 2008 and 2009 was not included in the ESC's benchmark forecast expenditure for 2006-10;[10] and

(b) recognised the importance of calculating the ECM carryover amounts for 2006-10 to be included in the annual revenue requirements for the 2006-10 regulatory control period by comparing reported expenditure for 2006-10 and the ESC's expenditure benchmarks for 2006-10 on a 'like for like' basis.[11]

10 However, the AER decided not to make Powercor Australia's proposed ECM adjustments in respect of its 2008 and 2009 expenditure necessarily incurred in achieving compliance with the 2005 Line Clearance Regulations (as modified by the Exemption). The AER's stated reasons for this decision are extracted, for the convenience of the Tribunal, in the Attachment to this submission.

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[7] RB (Legislation & authorities): Vol 1, Tab 3, pp 557-8.

[8] RB (Legislation & authorities): Vol 1, Tab 3, p 588.

[9] RB (Decisions & determinations): Vol 3, Tab 13.

[10] Final Decision, p 633 [RB (Decisions & determinations): Vol 3, Tab 13].

[11] Final Decision, p 629 [RB (Decisions & determinations): Vol 3, Tab 13]; see also section 13.2.4 (at pp 589-90) and section 13.5.5 (at pp 617-25).

POWERCOR AUSTRALIA'S SUBMISSIONS CONCERNING ERROR

11 Powercor Australia submits that, in deciding not to make the ECM adjustment proposed by it in respect of its 2008 and 2009 vegetation management expenditure:[12]

(a) the AER made an error or errors of fact in its findings of fact in finding that Powercor Australia had made a business decision independent of its legislative obligations to incur additional expenditure on vegetation management in 2008 and 2009; and

(b) further, having regard to the factual error(s) referred to in subparagraph (a) above and other errors made by the AER, the AER's decision to reject Powercor Australia's proposed adjustment to its actual operating expenditure was unreasonable and/or an incorrect exercise of discretion in all the circumstances.

12 The errors that Powercor Australia contends were made by the AER are set out in Powercor Australia's Submissions at paragraph 324[13] and are particularised in those Submissions at paragraphs 326 to 364[14].

THE PARTIES' AGREED POSITION ON ECM ADJUSTMENT GROUND

13 The AER submits[15], and Powercor Australia agrees, that:

(a) Powercor Australia incurred expenditure in 2008 and 2009 for the purposes of achieving compliance or ensuring that it was compliant with the 2005 Line Clearance Regulations (as modified by the Exemption) in respect of low voltage wires in LBRA;

(b) the expenditure incurred by Powercor Australia was additional to the expenditure forecasts of the ESC for 2006-10 in that it was expenditure of a kind that was not allowed by the ESC in those expenditure forecasts;

(c) the 'like for like' principle requires that the reported expenditure for 2006-10 and the expenditure forecasts of the ESC for 2006-10 used in calculating Powercor Australia's efficiency carryover amounts for 2006-10 must be stated on the same (that is, a 'like for like') basis in order that those efficiency carryover amounts reflect efficiency gains or losses;

(d) in the absence of an adjustment in the calculation of the efficiency carryover amounts for 2006-10 to exclude from Powercor Australia's actual expenditure for 2006-10 its additional expenditure on vegetation management in 2008 and

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[12] Powercor Australia's Submissions, p 90 at [366] [RB (Core documents): Vol 1, Tab 22].

[13] Powercor Australia's Submissions, pp 79-80 [RB (Core documents): Vol 1, Tab 22].

[14] Powercor Australia's Submissions, pp 80-9 [RB (Core documents): Vol 1, Tab 22].

[15] *The Australian Energy Regulator's Outline of Submissions concerning Powercor Australia's 2006-10 ECM Adjustment for Vegetation Management* dated 15 March 2011 (**AER's Submissions**) at [55]-[60] [RB (Submissions of the AER): Vol 1, Tab 1].

2009, Powercor Australia will be penalised for having incurred that additional expenditure in circumstances where this expenditure did not reflect any inefficiency;

(e) in failing to make an adjustment of the kind described in paragraph (d) above in respect of its 2008 and 2009 vegetation management expenditure in its Final Determination, the AER made a factual error insofar as it concluded that Powercor Australia incurred the 2008 and 2009 expenditure as a result of a business decision, rather than by way of endeavouring to achieve compliance with the 2005 Line Clearance Regulations (as modified by the Exemption) in respect of low voltage wires in LBRA;

(f) if the AER had made an adjustment of the kind described in paragraph (d) above, Powercor Australia's annual revenue requirements for the 2011-15 regulatory control period would be increased by the following amounts:

2011 (in $nominal)	2012 (in $nominal)	2013 (in $nominal)	2014 (in $nominal)	2015 (in $nominal)
$0	$10.54 million	$5.41 million	$3.79 million	$0

(g) Powercor Australia has established a ground of review within the meaning of section 71C of the Law[16].

14 The AER does not accept, however, that its decision to reject Powercor Australia's proposed adjustment to its actual operating expenditure was unreasonable and/or an incorrect exercise of discretion in all the circumstances.[17] The AER's submissions in that regard are set out in the AER's Submissions at paragraphs 40 to 50.[18]

15 Powercor Australia contests the matters contained in paragraphs 40 to 50 of the AER's Submissions.

DISPOSITION

16 In the AER's Submissions, it submits that the Tribunal should make a determination under section 71P of the Law varying the final determination regarding Powercor Australia (**Final Determination**)[19] by excluding the 2006-10 efficiency carryover amounts arising

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[16] RB (Legislation & authorities): Vol 1, Tab 1, p 87.

[17] AER's Submissions at [61]-[64] [RB (Submissions of the AER): Vol 1, Tab 1].

[18] [RB (Submissions of the AER): Vol 1, Tab 1].

[19] AER, *Final Powercor Australia Ltd Distribution determination 2011-15*, published on 29 October 2010 [RB (Decisions & determinations): Vol 2, Tab 11].

under the ESC's 2006-10 ECM from the annual revenue requirements for the 2011-15 regulatory control period.[20]

17 Powercor Australia agrees that this would form a part of the appropriate disposition of the ECM adjustment ground if the Tribunal determines, consistent with the submissions of Powercor Australia in support of its 2001-05 accrued negative carryover ground, that clause 6.4.3 of the Rules did not give the AER power to apply increments and decrements arising in any previous regulatory period including in particular the 2006-10 regulatory period. In these circumstances, Powercor Australia submits that the Tribunal should:

(a) as submitted by the AER, vary the Final Determination by replacing the annual revenue requirements for 2011-15 set out in Table 6 of the Final Determination with annual revenue requirements for 2011-15 that have been recalculated excluding (in addition to the 2001-05 accrued negative carryover arising under the ORG's 2001-05 ECM) the 2006-10 efficiency carryover amounts arising under the ESC's 2006-10 ECM; and

(b) also otherwise vary the Final Determination as required to give effect to the variation of the annual revenue requirements for 2011-15 set out in Table 6 of the Final Determination, including in particular the resultant recalculation of the x factors for standard control services set out in that Determination.

18 If, however, the Tribunal does not determine in respect of Powercor Australia's 2001-05 accrued negative carryover ground that clause 6.4.3 of the Rules did not give the AER power to apply increments and decrements arising in any previous regulatory period including in particular the 2006-10 regulatory period, Powercor Australia submits that the Tribunal should:

(a) vary the Final Determination by replacing and substituting the annual revenue requirements for the 2011-15 regulatory control period set out in Table 6 of the Final Determination with annual revenue requirements that have been increased by the amounts set out in paragraph 13(f) above, so as to reflect the 2006-10 efficiency carryover amounts arising under the ESC's 2006-10 ECM after they have been recalculated by making an adjustment to Powercor Australia's operating expenditure for 2008 and 2009 in the amount of $1,496,000 in $2008 and $4,948,000 in $2009 respectively; and

(b) otherwise varying the Final Determination as required to give effect to the variation of the annual revenue requirements, including in particular the resultant recalculation of the x factors for standard control services specified in the Final Determination.

Dated: 11 ~~July~~ 2011
August

[20] AER's Submissions at [65]-[67] [RB (Submissions of the AER): Vol 1, Tab 1].

Signed on behalf of the AER	Signed on behalf of the Applicant
F Williams of Corrs Chambers Westgarth	
Frances Williams	Fleur Gibbons
Solicitor for the AER	Solicitor for Powercor Australia

ATTACHMENT - AER'S REASONS FOR DECISION

The AER's stated reasons for deciding, in its Final Decision, not to make Powercor Australia's proposed ECM adjustments in respect of its 2008 and 2009 expenditure necessarily incurred in achieving compliance with the 2005 Line Clearance Regulations (as modified by the Exemption) were as follows:[21]

> *Powercor's vegetation management costs*
>
> Powercor also proposes to exclude vegetation management costs incurred in 2008 and 2009 on the basis that these costs reflected an uncontrollable change in the scope of Powercor's activities. In particular, Powercor argued that it has incurred more costs than was assumed in the ESCV's benchmark allowance. Powercor stated that these costs have been incurred on the expectation that an exemption from its obligations under these regulations that was issued by the ESCV was expected to expire.
>
> In considering this issue the AER notes that this expenditure is not non-recurrent expenditure as CitiPower and Powercor has sought increased opex in the forthcoming regulatory control period (the AER's assessment of this opex is discussed in chapter 7). The AER has accepted that non-recurrent expenditure in the base year should be excluded from the efficiency carryover calculation (refer to section 13.5.6.4). The AER notes in this circumstance the additional costs incurred by Powercor are reflected in its base year cost such that the AER's concerns regarding the incentives to pursue efficiencies does not arise in relation to Powercor's vegetation management costs.
>
> The AER notes that Powercor considers this expenditure to be an uncontrollable cost associated with a change in the scope of its activities. The AER further notes that CitiPower and Powercor have provided evidence that these additional costs were not included in the ESCV benchmark allowance. While the AER accepts that these additional costs have not been included in the ESCV benchmark allowance, the AER does not consider that an adjustment to remove these costs from actual opex in the efficiency carryover calculation is consistent with the ORG's Appeal Panel Decision nor the ESCV's 'like for like principle'. As discussed above, the ORG Appeal Panel decision considered that an adjustment should be made for network growth to ensure a 'like for like' comparison between the benchmark allowances and actual opex. In respect of the ESCV's approach to ensuring a 'like for like' comparison, as discussed previously the AER has applied the adjustments to the Victorian DNSPs:
>
> - consistent with past ORG/ESCV practice
> - the ORG considered that it was not appropriate to adjust the ECM for uncontrollable costs and this issues [sic] was not identified by the ESCV in its 2006 EDPR
> - the decision by the AER not to make this adjustment is not inconsistent with its approach to apply adjustments elsewhere and with the ORG/ESCV's past practice.
>
> The AER notes that while there may be sound business reasons for Powercor to have incurred these costs, the AER does not consider that an adjustment to remove the costs incurred by Powercor in 2008 and 2009 for vegetation management costs is consistent with the 'like for like' principle. That is the AER notes that Powercor has incurred costs in anticipation that its exemption would cease after the expiry of this exemption in June 2010. However, the AER notes that the ESV advised the Victorian DNSPs that this exemption would expire on 13 October 2009. Accordingly, the AER notes that Powercor has made a business decision independent of its legislative obligations to incur additional expenditure in 2008 and 2009. The AER therefore does not consider it appropriate for Powercor's efficiency carryover amounts to be adjusted for this additional expenditure in 2008 and 2009. The AER has, however, included these costs in Powercor's forecast opex for the forthcoming regulatory control period. This means that Powercor will incur a negative efficiency amount but this will be will be [sic] offset by a higher forecast allowance over the 2006-10 regulatory control period.

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[21] Final Decision, pp 633-5 [RB (ECM Adjustment): Vol 2, Tab 32, pp 991-3].

> The AER does not consider that Powercor's proposed adjustment is consistent with the NEO and 7A (2)(3) [sic] of the NEL as contended by Powercor. The AER considers that Powercor should share the efficiency losses of this additional expenditure with customers on the basis that Powercor has incurred additional costs over the regulatory period, [sic] Specifically, the AER does not accept that Powercor has incurred additional costs related to meeting any legislative requirements in the 2006-10 regulatory period and therefore some of these efficiency losses should be borne by Powercor before these additional costs are passed back to customers. This maintains a symmetrical treatment to efficiencies under the ECM by recognising both efficiency gains and losses which the AER regards as being consistent with the NEO section 7(A)(3) [sic] of the NEL and 6.5.8(c) of the NER for the reasons outlined in section 13.5.3.3.
>
> The AER also notes that the principle in section 7A (2) of the NEL requires the DNSPs to be provided with a reasonable opportunity to recover efficient costs. Because Powercor will be compensated for the costs it incurred in the base year (2009) as these cost [sic] are reflected in Powercor' [sic] opex forecast for the 2011-15 regulatory control period, Powercor will not be denied a reasonable opportunity to recover its efficient costs by including Powercor's vegetation cost in the calculation of efficiency carryover amounts.
>
> In conclusion, the AER, in calculating the efficiency carryover amounts from the ESCV's ECM, has not adjusted the benchmark allowance for uncontrollable costs for CitiPower and Powercor.

The prior discussion of the ORG Appeal Panel Decision and the ESC's 'like for like' principle referred to in the above reasons for decision reads as follows:[22]

> In response to CitiPower and Powercor's view that the ESCV adopted a general 'like for like' principle the AER agrees with the ESCV's statement 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 (referred to as the 'like for like' principle). The AER also notes that in ESCV [sic] commented that
>
> > This highlights the importance of clearly establishing the basis for the estimated expenditure for the 2006-10 regulatory period. It is also consistent with the Commission requiring adequate disclosure so that adjustments can be made to compare information on a 'like for like' basis over time, across businesses and with benchmarks.
>
> The AER noted in the draft decision that the ESCV identified a number of adjustments that it considered necessary to ensure a 'like for like' comparison between the benchmark allowance and actual opex. The AER noted that these adjustments were limited to:
>
> - growth adjustments
> - capitalisation of overheads and
> - movements in provisions (that is, non cash items).
>
> The AER also noted that the ESCV excluded related party margins (referred to as contractual arrangements) from the Victorian DNSPs' forecast opex allowance. The AER has, therefore excluded related party margins in determining the Victorian DNSPs [sic] carryover amounts to maintain a 'like for like' comparison between the ESCV benchmark allowance and actual opex. This adjustment has been accepted by the Victorian DNSPs (refer to section 13.5.5). The AER considers that the adjustments made in the draft decision are consistent with past ORG/ESCV (and intended ESCV practice in relation to related party margins given that the ESCV excluded related party margins from the Victorian DNSPs [sic] benchmark allowances for 2006-10). It follows that the AER does not consider that it has been inconsistent in applying these adjustments by not accepting CitiPower and Powercor's proposed adjustments. That said the AER also, for the reasons discussed below, does not consider that CitiPower and Powercor have demonstrated that these adjustments are consistent with the 'like for like' principle.

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[22] Final Decision, pp 628-9 [RB (ECM adjustment): Vol 2, Tab 32, pp 986-7].

The AER in the draft decision reviewed the Appeal Panel Decision for the 2001-05 EDPR and maintains that the Appeal Panel rejected the ORG's 2000 decision not to make provision for ex post adjustments to Powercor's benchmark allowances for the 1995-99 period associated with network growth. As discussed above the AER has adjusted CitiPower and Powercor's ESCV benchmark allowances for network growth (refer to section 13.5.4).