Final decision - appendices

Victorian electricity distribution network service providers

Distribution determination 2011–2015

October 2010

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A Submissions

The AER received submissions on its draft decision from the following interested parties:

Citelum Australia

Citipower Pty

Citipower Pty, Powercor Australia Ltd and United Energy joint submission

City of Darebin

Commonwealth Scientific and Industrial Research Organisation (CSIRO)

Consumer Action Law Centre

Consumer Utilities Advocacy Centre

EnergyAustralia

Energy Response Pty Ltd

Energy Users Association of Australia

Energy Users Coalition of Victoria

EziKey Group Pty Ltd (trading as WireAlert)

Grid Australia

Jemena Electricity Networks (Vic) Ltd

Northern Alliance for Greenhouse Action

Origin Energy Retail Ltd

Sylvania Lighting Australasia Pty Ltd

The Hon. Peter Bachelor MP, Minister for Energy and Resources, Victoria

Total Environment Centre Inc.

Trans Tasman Energy Group

TRU Energy Pty Ltd

United Energy Distribution Pty Ltd

Victorian Council of Social Services

Victorian Employers Chamber of Commerce and Industry

Visy

B Service classification

Table B.1 AER's final decision on service classification

Service grouping	Services	AER classification
Network services	Constructing the distribution network Maintaining distribution network and connection assets Operating the distribution network and connection assets for DNSP purposes Designing the distribution network Planning the distribution network Emergency response Administrative support (e.g. call centre, network billing) Location of underground cables ('dial before you dig')	Standard control services
Connection services	New connections requiring augmentations	Standard control services
Metering services	Meter investigation De-energisation of existing connections Energisation of existing connections Special meter reading Re-test of type 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh	Alternative control services - fee based
Public lighting services	Operation, repair, replacement and maintenance of DNSP public lighting assets	Alternative control services - fee based

	Alternation and relocation of DNSP public lighting assets New public lighting assets (that is, new lighting types not subject to a regulated charge and new public lighting at greenfields sites)	Negotiated services
Quoted services	Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets Supply enhancement at customer request Supply abolishment Emergency recoverable works Auditing design and construction Specification and design enquiry fees Elective undergrounding where above ground service currently exists Damage to overhead service cables caused by high load vehicles High load escorts - lifting overhead lines Covering of low voltage mains for safety reasons Routine connections - customers above 100 amps After hours truck by appointment	Alternative control services - quoted services

Fee based services	Fault response - not DNSP fault Temporary disconnect/reconnect services Wasted attendance - not DNSP fault Service truck visits Reserve feeder PV installation Routine connections - customers below 100 amps Temporary supply services	Alternative control services - fee based
Unclassified services	Provision of possum guards Repair, installation and maintenance of watchman lights	Unregulated service

Source: AER analysis

C Negotiating frameworks

In accordance with cl. 6.12.1 (15), the approved Victorian DNSPs negotiating frameworks are set out below.

CitiPower Pty

Proposed negotiating framework

Regulatory control period

Commencing 1 January 2011

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Background

A. Clause 6.7.5 of the National Electricity Rules (**NER**) provides that a *Distribution Network Service Provider* (**DNSP**) must prepare a document (the *negotiating framework)* setting out the procedure to be followed during negotiations between that DNSP and any person (the *Service Applicant* or applicant) who wishes to receive a *negotiated distribution service* from the DNSP, as to the *terms and conditions of access* for the provision of the service.

B. The *negotiating framework* must comply with and be consistent with:

(a) the applicable requirements of the relevant distribution determination; and

(b) paragraph 6.7.5(c) of the NER, which sets out the minimum requirements for a *negotiating framework.*

C. This document sets out the proposed *negotiating framework* of CitiPower Pty (**CitiPower**), which has been prepared by CitiPower in accordance with clause 6.7.5 of the NER.

1 Application of *negotiating framework*

1.1 CitiPower and any *Service Applicant* who is negotiating for the provision of a *negotiated distribution service* by CitiPower must comply with the requirements of this *negotiating framework* in accordance with its terms.

1.2 The requirements set out in this document are additional to any requirements or obligations:

(a) contained in clauses 5.3 and 5.5 of the NER insofar as the *negotiating framework* applies to *negotiated distribution services* which would have been *negotiated distribution services* regardless of the operation of clause 6.24.2(c) of the NER;

(b) contained in clauses 5.5 and 5.4A of the NER insofar as the *negotiating framework* applies to *negotiated distribution services* which would have been treated as *negotiated transmission services* were it not for the operation of clause 6.24.2(c) of the NER; and

(c) contained in any other relevant provisions of Chapter 6 of the NER.

In the event of any inconsistency between this document and the requirements of the NER, the requirements of the NER will prevail to the minimum extent of the inconsistency.

1.3 Nothing in this document will be taken as imposing an obligation on CitiPower to provide any service to the *Service Applicant*.

2 Obligation to negotiate in good faith

2.1 CitiPower and the *Service Applicant* must negotiate in good faith the *terms and conditions of access* to a *negotiated distribution service*.

2.2 The obligation to negotiate in good faith under clause 2.1 does not:

(a) create any fiduciary rights or obligations between the parties; or

(b) require a party to act contrary to its own commercial interests.

3 Provision of commercial information by CitiPower

3.1 The *Service Applicant* may give notice to CitiPower requesting commercial information that the *Service Applicant* reasonably requires to enable it to engage in effective negotiation with CitiPower for the provision of the *negotiated distribution service*.

3.2 CitiPower must provide all such commercial information a *Service Applicant* requests in accordance with clause 3.1, being commercial information the *Service Applicant* reasonably requires to enable that applicant to engage in effective negotiation with CitiPower for the provision of the *negotiated distribution service*.

3.3 CitiPower must provide to the *Service Applicant*, regardless of whether it is requested by the *Service Applicant* in accordance with clause 3.1:

(a) the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the *negotiated distribution service*;

(b) how the charges for providing the *negotiated distribution service* reflect those costs and/or the cost increment or decrement (as appropriate); and

(c) the appropriate arrangements for assessment and review of the charges and the basis on which they are made.

3.4 Commercial information to be provided to a *Service Applicant* pursuant to this clause 3 does not include:

(a) *confidential information* provided to CitiPower by another person; or

(b) information that CitiPower is prohibited, by law, from disclosing to the *Service Applicant*.

3.5 Commercial information provided to a *Service Applicant* pursuant to this clause 3 may be provided subject to conditions including:

(a) a condition that the *Service Applicant* must not disclose any part of that commercial information to any other person without the prior written consent of CitiPower; and/or

(b) a condition that the *Service Applicant* (or any other person to whom the *Service Applicant* seeks to disclose the commercial information) must enter into a confidentiality agreement with CitiPower, on terms reasonably acceptable to both parties before disclosure of the commercial information to that person.

4 Provision of commercial information by Service Applicant

4.1 CitiPower may give notice to the *Service Applicant* requesting commercial information that CitiPower reasonably requires to enable CitiPower to engage in effective negotiation with that applicant for the provision of the *negotiated distribution service*.

4.2 The *Service Applicant* must provide all commercial information CitiPower requests in accordance with clause 4.1, being commercial information CitiPower reasonably requires to enable the provider to engage in effective negotiation with that applicant for the provision of the *negotiated distribution service*.

4.3 Subject to clause 4.5, the *Service Applicant* must use its reasonable endeavours to provide CitiPower with the commercial information requested under clause 4.1 within 10 business days of that request, or within such other time period as agreed by the parties.

4.4 The *Service Applicant* must use its reasonable endeavours to provide to CitiPower within 10 business days of the application being provided to CitiPower, and regardless of whether it is requested by CitiPower in accordance with clause 4.1:

(a) details of the corporate structure of the *Service Applicant*, financial details relevant to credit worthiness and credit risk and ownership of assets;

(b) technical information relevant to the application for a *negotiated distribution service*;

(c) financial information relevant to the application for a *negotiated distribution service*;

(d) details of the compliance of the *Service Applicant*'s application with any law, standard, NER or guideline.

4.5 Commercial information to be provided to CitiPower pursuant to this clause 4 does not include:

(a) *confidential information* provided to the *Service Applicant* by another person; or

(b) information that the *Service Applicant* is prohibited, by law, from disclosing to CitiPower.

4.6 Commercial information provided to CitiPower pursuant to this clause 4 may be provided subject to conditions including:

(a) a condition that CitiPower must not disclose any part of that commercial information to any other person without the prior written consent of the *Service Applicant*; and/or

(b) a condition that CitiPower (or any other person to whom CitiPower seeks to disclose the commercial information) must enter into a confidentiality agreement with the *Service Applicant*, on terms reasonably acceptable to both parties before the disclosure of the confidential information to that person.

5 Determination of impact on other *Distribution Network Users*

5.1 CitiPower must determine the potential impact on *Distribution Network Users*, other than the *Service Applicant*, of the provision of the *negotiated distribution service* to the *Service Applicant*.

5.2 CitiPower must notify and consult with any affected *Distribution Network Users* and ensure that the provision of the *negotiated distribution service* to which access is sought by the *Service Applicant* does not result in non-compliance with obligations in relation to other *Distribution Network Users* under the NER.

6 Timeframe for negotiations

6.1 The target timeframe for commencing, progressing and finalising negotiations for the supply of a *negotiated distribution service*, as to the *terms and conditions of access* for the provision of the service, is set out in Table 1.

6.2 The timeframe set out in Table 1 will not apply where a timeframe is specified in Chapter 5 of the NER in relation an application for a *negotiated distribution service.*

6.3 CitiPower and the *Service Applicant* must use reasonable endeavours to adhere to the timeframe set out in Table 1, as well as to any preliminary program finalised under D. in Table 1, including as amended from time to time in accordance with this clause 6.

6.4 The timeframe set out in Table 1 may be suspended in accordance with clause 7.

6.5 The timeframe set out in Table 1 may be varied by agreement between CitiPower and the *Service Applicant*, where such agreement must not be unreasonably withheld or delayed.

6.6 Any preliminary program finalised under D. in Table 1 may be modified from time to time by further agreement between CitiPower and the *Service Applicant*, where such agreement must not be unreasonably withheld or delayed.

Table 1 - Target timeframe for negotiations

	Event	Target timeframe
A.	CitiPower receives written application a *negotiated distribution service* from the *Service Applicant*	X
B.	The *Service Applicant* provides to CitiPower the commercial information set out in clause 4.4	X + 10 business days
C.	CitiPower and the *Service Applicant may* meet to discuss a preliminary program setting out a reasonable period of time for commencing, progressing and finalising negotiations	X + 10 business days
D.	CitiPower and the *Service Applicant* finalise the preliminary program for commencing, progressing and finalising negotiations. The program may include milestones relating to: • the provision of information by CitiPower pursuant to clause 3; • the provision of information by the *Service Applicant* pursuant to clause 4; • the notification and consultation with any affected *Distribution Network Users* in accordance with clause 5.2; and/or • the notification by CitiPower of the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service* pursuant to clause 10.1.	X + 25 business days
E.	CitiPower provides the *Service Applicant* with an offer for the *negotiated distribution service*	In accordance with agreed program
F.	CitiPower and the *Service Applicant* finalise negotiations	In accordance with agreed program

7 Suspension of timeframe for negotiations

7.1 The timeframes for negotiation of provision of a *negotiated distribution service* in Table 1 or agreed between the parties are suspended if:

(a) a dispute in relation to the *negotiated distribution service* is notified to the Australian Energy Regulator (**AER**) under Part 10 of the National Electricity Law (**NEL**), from the date of the notification of that dispute to the AER until:

- the withdrawal of the dispute under section 126 of the NEL;
- the termination of the dispute by the AER under section 131 or section 132 of the NEL; or
- a determination is made in respect of the dispute by the AER in accordance with section 128 of the NEL;

(b) after 15 business days of CitiPower requesting commercial information under clause 4.1, or, where an alternative timeframe for the provision of the commercial information has been agreed pursuant to clause 4.3, after 5 business days after the date agreed for the provision of the requested commercial information, the *Service Applicant* has not provided that information;

(c) after 15 business days of providing the application to CitiPower, the *Service Applicant* fails to provide the information commercial information set out in clause 4.4;

(d) the *Service Applicant* fails to pay the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service* in accordance with clause 10, from the next business day after the amount is due until such time as the *Service Applicant* has paid the outstanding amount; and/or

(e) where CitiPower has been required to notify and consult with any affected *Distribution Network Users* in accordance with clause 5.2, from the date of the notification to the affected *Distribution Network User* until the end of the time limit specified by CitiPower for any affected *Distribution Network Users* to provide to CitiPower information regarding the impact of the provision of the *negotiated distribution service*, or the date on which CitiPower receives such information from the affected *Distribution Network Users,* whichever is the later.

7.2 Each party will notify the other party if it considers that the timeframe has been suspended, within 5 business days of the date that the party considers the suspension took effect.

8 Publication of the results of negotiations

8.1 CitiPower will publish on its website the results of negotiations for access to a *negotiated distribution service*.

9 Dispute resolution

9.1 All disputes as to the *terms and conditions of access* for the provision of *negotiated distribution services* are to be dealt with in accordance with Part 10 of the NEL and Part L of Chapter 6 of the NER.

10 Payment of CitiPower's reasonable direct expenses

10.1 From time to time, CitiPower may give the *Service Applicant* a notice setting out the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service*.

10.2 The *Service Applicant* must, within 20 business days of the notice given pursuant to clause 10.1, pay to CitiPower the amount set out in the notice in the manner set out in the notice.

10.3 If the *Service Applicant* fails to pay any sum due for payment under this clause 10 on the due date, the *Service Applicant* must pay interest on that sum from the due date until the date of actual payment at the Default Rate. Interest is to be calculated on a daily basis and capitalised monthly.

11 Termination of negotiations

11.1 The *Service Applicant* may elect not to continue with its application for a *negotiated distribution service* and may terminate negotiations by giving CitiPower written notice of its decision to do so.

11.2 CitiPower may terminate negotiations under this *negotiating framework* by giving the *Service Applicant* written notice of its decision to do so where:

(a) CitiPower believes on reasonable grounds that the *Service Applicant* is not conducting the negotiations under this *negotiating framework* in good faith;

(b) after 30 business days from the date of a notice issued under clause 10.1, the *Service Applicant* has failed to pay to CitiPower the amount set out in the notice;

(c) there are multiple or recurring failures by the *Service Applicant* to comply with the requirements of the *negotiating framework*;

(d) the *Service Applicant* fails to comply with an obligation in this *negotiating framework* to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action to the reasonable satisfaction of CitiPower within 20 business days of a written request from CitiPower; or

(e) a Solvency Default occurs in relation to the *Service Applicant.*

11.3 For the avoidance of doubt, in the event negotiations are terminated pursuant to this clause 11:

(a) CitiPower may nonetheless give notice under clause 10.1 for the recovery of the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service* and the *Service Applicant* must pay the amount set out in the notice in accordance with clause 10.2, along with any applicable interest payable under clause 10.3; and

(b) A party must return all commercial information provided to it by or on behalf of the other party in respect of this *negotiating framework* or, if requested by the other party, destroy all copies of the commercial information in its possession or control, in either case within 5 business days' of request.

12 GST

12.1 Any reference to costs, expenses, consideration and other amounts in this *negotiating framework* or provided under or in connection with it are exclusive of GST, unless expressed to be GST-inclusive.

12.2 Where CitiPower makes a taxable supply to the *Service Applicant* under or in connection with this *negotiating framework*, the *Service Applicant* must pay to CitiPower an additional amount equal to the GST payable on the supply (unless the consideration for that taxable supply is expressed to include GST). The additional amount must be paid by the *Service Applicant* at the later of the following:

12.2.1 The date when any consideration for the taxable supply is first paid or provided.

12.2.2 The date when CitiPower issues a tax invoice to the *Service Applicant*.

12.3 If, under or in connection with this *negotiating framework*, CitiPower has an adjustment for a supply under the GST Act which varies the amount of GST payable by CitiPower, CitiPower will adjust the amount payable by the *Service Applicant* to take account of the varied GST amount. CitiPower must issue an adjustment note to the *Service Applicant* within 28 days of becoming aware of the adjustment.

12.4 If a party is entitled to be reimbursed or indemnified under or in connection with this *negotiating framework*, the amount to be reimbursed or indemnified is reduced by the amount of GST for which there is an entitlement to claim an input tax credit on an acquisition associated with the reimbursement or indemnity. The reduction is to be made before any increase under clause 12.2. An entity is assumed to be entitled to a full input tax credit on an acquisition associated with the reimbursement or indemnity unless it demonstrates otherwise before the date the reimbursement or indemnity is made.

12.5 This clause 12 will not merge on completion and will survive the termination of this document by any party (including for the avoidance of doubt termination of negotiations under this *negotiating framework*).

12.6 Terms used in this clause that are not otherwise defined in this *negotiating framework* have the meanings given to them in the GST Act.

13 Notices

Giving notices

13.1 Any notice or communication given to CitiPower under this *negotiating framework* is only given if it is in writing and sent in one of the following ways:

(a) delivered or posted to CitiPower at its address and marked for the attention of the relevant officer set out below;

(b) faxed to CitiPower at its fax number and marked for the attention of the relevant officer set out below.

Name: CitiPower Pty

Address: Locked Bag 14090 Melbourne 8001

Fax number: 9683-4499

Attention: Manager Customer Connections

13.2 Any notice, consent, information or request given or made under this document is only given or made to the *Service Applicant* if it is in writing and delivered to the *Service Applicant* at the address or fax number specified in the *Service Applicant*'s application and marked for the attention of the relevant officer specified in the application.

Change of address or facsimile number

13.3 If a party gives the other party three business days notice of a change of its address or facsimile number, any notice or communication is only given by that other party if it is delivered, posted or faxed to the latest address or fax number.

Time notices are given

13.4 Any notice or communication is to be treated as given at the following time:

(a) if it is delivered, when it is left at the relevant address;

(b) if it is sent by post, two business days after it is posted;

(c) if it is sent by fax, as soon as the sender receives from the sender's fax machine a report of an error free transmission to the correct fax number.

13.5 However, if any notice or communication is given, on a day that is not a business day or after 5pm on a business day, in the place of the party to whom it is sent it is to be treated as having been given at the beginning of the next business day.

14 Miscellaneous

Governing law and jurisdiction

14.1 This document is governed by the law of Victoria. The parties submit to the non-exclusive jurisdiction of its courts and courts of appeal from them. The parties will not object to the exercise of jurisdiction by those courts on any basis.

Rights cumulative

14.2 The rights and remedies of a party under this document are in addition to and do not replace or limit any other rights or remedies that the party may have.

Severability

14.3 Each provision of this document is individually severable. If any provision is or becomes illegal, unenforceable or invalid in any jurisdiction it is to be treated as being severed from this document in the relevant jurisdiction, but the rest of this document will not be affected. The legality, validity and enforceability of the provision in any other jurisdiction will not be affected.

Interpretation

14.4 In this document the following definitions apply:

Bill Rate means the 90 day bank bill swap reference rate (source: Bloomberg) as quoted in the Australian Financial Review (or some equivalent rate if quotation or the rate ceases) on the first business day following the due date.

CitiPower means CitiPower Pty (ABN 76 064 651 056) of 40 Market Street Melbourne 8001.

Control means, in relation to an entity, the power to directly or indirectly:

(a) control the membership of the board of directors or other governing body of the entity;

(b) control the entity applying section 50AA of the Corporations Act 2001;

(c) where the entity is trustee of a trust, to appoint, remove or replace the trustee or direct the trustee as to decisions to be made in relation to the trust; or

(d) direct the management and policies of that entity, whether by means of trusts, agreements, arrangements, undertakings, practices, the ownership of any interest in shares or in any other way.

Default Rate means the Bill Rate applicable at the time of the default plus 4%.

GST Act means *A New Tax System (Goods and Services Tax) Act 1999* (Cth).

Solvency Default means the occurrence of any of the following events in relation to the *Service Applicant*:

(a) A step being taken to wind up the *Service Applicant*;

(b) A receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the *Service Applicant*, or a provisional liquidator is appointed to the *Service Applicant*;

(c) A mortgagee, charge or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the *Service Applicant*;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The *Service Applicant* stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The *Service Applicant* applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the *Service Applicant* or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the *Service Applicant's* property;

(h) The *Service Applicant* takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the *Service Applicant* or any part of its property;

(i) Except to reconstruct or amalgamate while solvent, the *Service Applicant* enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the *Service Applicant's* affairs;

(j) The *Service Applicant* is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001;

(k) The *Service Applicant* ceases or threatens to cease to carry on its main business;

(l) Anything analogous or having substantially similar effect to any of the events specified above happens in relation to the *Service Applicant*;

(m) Anything else occurs that reasonably indicates that there is a significant risk that the *Service Applicant* is or will become unable to pay its debts as they fall due; or

(n) Any of the above happens to an entity that Controls the *Service Applicant.*

14.5 In the interpretation of this document, the following provisions apply unless the context otherwise requires:

(a) In this *negotiating framework* the words in italics have the meaning given to them in the NEL and the NER.

(b) Headings are inserted for convenience only and do not affect the interpretation of this document.

(c) A reference in this document to a business day means a day other than a Saturday or Sunday on which banks are open for business generally in Melbourne, Victoria.

(d) If the day on which any act, matter or thing is to be done under this document is not a business day, the act, matter or thing must be done on the next business day.

(e) A reference in this document to any law, legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision.

(f) A reference in this document to any document or agreement is to that document or agreement as amended, novated, supplemented or replaced.

(g) Unless otherwise stated, a reference to a clause, part, schedule or attachment is a reference to a clause, part, schedule or attachment of or to this document.

(h) An expression importing a natural person includes any company, trust, partnership, joint venture, association, body corporate or governmental agency.

(i) Where a word or phrase is given a defined meaning, another part of speech or other grammatical form in respect of that word or phrase has a corresponding meaning.

(j) A word which indicates the singular also indicates the plural, a word which indicates the plural also indicates the singular, and a reference to any gender also indicates the other gender.

(k) A reference to the word 'include' or 'including' is to be interpreted without limitation.

Powercor Australia Pty

Proposed negotiating framework

Regulatory control period
Commencing 1 January 2011

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Background

A. Clause 6.7.5 of the National Electricity Rules (**NER**) provides that a *Distribution Network Service Provider* (**DNSP**) must prepare a document (the *negotiating framework)* setting out the procedure to be followed during negotiations between that DNSP and any person (the *Service Applicant* or applicant) who wishes to receive a *negotiated distribution service* from the DNSP, as to the *terms and conditions of access* for the provision of the service.

B. The *negotiating framework* must comply with and be consistent with:

(a) the applicable requirements of the relevant distribution determination; and

(b) paragraph 6.7.5(c) of the NER, which sets out the minimum requirements for a *negotiating framework.*

C. This document sets out the proposed *negotiating framework* of Powercor Australia Pty (**Powercor Australia**), which has been prepared by Powercor Australia in accordance with clause 6.7.5 of the NER.

1 Application of *negotiating framework*

1.1 Powercor Australia and any *Service Applicant* who is negotiating for the provision of a *negotiated distribution service* by Powercor Australia must comply with the requirements of this *negotiating framework* in accordance with its terms.

1.2 The requirements set out in this document are additional to any requirements or obligations:

(a) contained in clauses 5.3 and 5.5 of the NER insofar as the *negotiating framework* applies to *negotiated distribution services* which would have been *negotiated distribution services* regardless of the operation of clause 6.24.2(c) of the NER;

(b) contained in clauses 5.5 and 5.4A of the NER insofar as the *negotiating framework* applies to *negotiated distribution services* which would have been treated as *negotiated transmission services* were it not for the operation of clause 6.24.2(c) of the NER; and

(c) contained in any other relevant provisions of Chapter 6 of the NER.

In the event of any inconsistency between this document and the requirements of the NER, the requirements of the NER will prevail to the minimum extent of the inconsistency.

1.3 Nothing in this document will be taken as imposing an obligation on Powercor Australia to provide any service to the *Service Applicant*.

2 Obligation to negotiate in good faith

2.1 Powercor Australia and the *Service Applicant* must negotiate in good faith the *terms and conditions of access* to a *negotiated distribution service*.

2.2 The obligation to negotiate in good faith under clause 2.1 does not:

(a) create any fiduciary rights or obligations between the parties; or

(b) require a party to act contrary to its own commercial interests.

3 Provision of commercial information by Powercor Australia

3.1 The *Service Applicant* may give notice to Powercor Australia requesting commercial information that the *Service Applicant* reasonably requires to enable it to engage in effective negotiation with Powercor Australia for the provision of the *negotiated distribution service*.

3.2 Powercor Australia must provide all such commercial information a *Service Applicant* requests in accordance with clause 3.1, being commercial information the *Service Applicant* reasonably requires to enable that applicant to engage in effective negotiation with Powercor Australia for the provision of the *negotiated distribution service*.

3.3 Powercor Australia must provide to the *Service Applicant*, regardless of whether it is requested by the *Service Applicant* in accordance with clause 3.1:

(a) the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the *negotiated distribution service*;

(b) how the charges for providing the *negotiated distribution service* reflect those costs and/or the cost increment or decrement (as appropriate); and

(c) the appropriate arrangements for assessment and review of the charges and the basis on which they are made.

3.4 Commercial information to be provided to a *Service Applicant* pursuant to this clause 3 does not include:

(a) *confidential information* provided to Powercor Australia by another person; or

(b) information that Powercor Australia is prohibited, by law, from disclosing to the *Service Applicant*.

3.5 Commercial information provided to a *Service Applicant* pursuant to this clause 3 may be provided subject to conditions including:

(a) a condition that the *Service Applicant* must not disclose any part of that commercial information to any other person without the prior written consent of Powercor Australia; and/or

(b) a condition that the *Service Applicant* (or any other person to whom the *Service Applicant* seeks to disclose the commercial information) must enter into a confidentiality agreement with Powercor Australia, on terms reasonably acceptable to both parties before disclosure of the commercial information to that person.

4 Provision of commercial information by Service Applicant

4.1 Powercor Australia may give notice to the *Service Applicant* requesting commercial information that Powercor Australia reasonably requires to enable Powercor Australia to engage in effective negotiation with that applicant for the provision of the *negotiated distribution service*.

4.2 The *Service Applicant* must provide all commercial information Powercor Australia requests in accordance with clause 4.1, being commercial information Powercor Australia reasonably requires to enable the provider to engage in effective negotiation with that applicant for the provision of the *negotiated distribution service*.

4.3 Subject to clause 4.5, the *Service Applicant* must use its reasonable endeavours to provide Powercor Australia with the commercial information requested under clause 4.1 within 10 business days of that request, or within such other time period as agreed by the parties.

4.4 The *Service Applicant* must use its reasonable endeavours to provide to Powercor Australia within 10 business days of the application being provided to Powercor Australia, and regardless of whether it is requested by Powercor Australia in accordance with clause 4.1:

(a) details of the corporate structure of the *Service Applicant*, financial details relevant to credit worthiness and credit risk and ownership of assets;

(b) technical information relevant to the application for a *negotiated distribution service*;

(c) financial information relevant to the application for a *negotiated distribution service*;

(d) details of the compliance of the *Service Applicant*'s application with any law, standard, NER or guideline.

4.5 Commercial information to be provided to Powercor Australia pursuant to this clause 4 does not include:

(a) *confidential information* provided to the *Service Applicant* by another person; or

(b) information that the *Service Applicant* is prohibited, by law, from disclosing to Powercor Australia.

4.6 Commercial information provided to Powercor Australia pursuant to this clause 4 may be provided subject to conditions including:

(a) a condition that Powercor Australia must not disclose any part of that commercial information to any other person without the prior written consent of the *Service Applicant*; and/or

(b) a condition that Powercor Australia (or any other person to whom Powercor Australia seeks to disclose the commercial information) must enter into a confidentiality agreement with the *Service Applicant*, on terms reasonably acceptable to both parties before the disclosure of the confidential information to that person.

5 Determination of impact on other *Distribution Network Users*

5.1 Powercor Australia must determine the potential impact on *Distribution Network Users*, other than the *Service Applicant*, of the provision of the *negotiated distribution service* to the *Service Applicant*.

5.2 Powercor Australia must notify and consult with any affected *Distribution Network Users* and ensure that the provision of the *negotiated distribution service* to which access is sought by the *Service Applicant* does not result in non-compliance with obligations in relation to other *Distribution Network Users* under the NER.

6 Timeframe for negotiations

6.1 The target timeframe for commencing, progressing and finalising negotiations for the supply of a *negotiated distribution service*, as to the *terms and conditions of access* for the provision of the service, is set out in Table 1.

6.2 The timeframe set out in Table 1 will not apply where a timeframe is specified in Chapter 5 of the NER in relation an application for a *negotiated distribution service.*

6.3 Powercor Australia and the *Service Applicant* must use reasonable endeavours to adhere to the timeframe set out in Table 1, as well as to any preliminary program finalised under D. in Table 1, including as amended from time to time in accordance with this clause 6.

6.4 The timeframe set out in Table 1 may be suspended in accordance with clause 7.

6.5 The timeframe set out in Table 1 may be varied by agreement between Powercor Australia and the *Service Applicant*, where such agreement must not be unreasonably withheld or delayed.

6.6 Any preliminary program finalised under D. in Table 1 may be modified from time to time by further agreement between Powercor Australia and the *Service Applicant*, where such agreement must not be unreasonably withheld or delayed.

Table 1 - Target timeframe for negotiations

	Event	Target timeframe
A.	Powercor Australia receives written application a *negotiated distribution service* from the *Service Applicant*	X
B.	The *Service Applicant* provides to Powercor Australia the commercial information set out in clause 4.4	X + 10 business days
C.	Powercor Australia and the *Service Applicant may* meet to discuss a preliminary program setting out a reasonable period of time for commencing, progressing and finalising negotiations	X + 10 business days
D.	Powercor Australia and the *Service Applicant* finalise the preliminary program for commencing, progressing and finalising negotiations. The program may include milestones relating to: • the provision of information by Powercor Australia pursuant to clause 3; • the provision of information by the *Service Applicant* pursuant to clause 4; • the notification and consultation with any affected *Distribution Network Users* in accordance with clause 5.2; and/or • the notification by Powercor Australia of the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service* pursuant to clause 10.1.	X + 25 business days
E.	Powercor Australia provides the *Service Applicant* with an offer for the *negotiated distribution service*	In accordance with agreed program
F.	Powercor Australia and the *Service Applicant* finalise negotiations	In accordance with agreed program

7 Suspension of timeframe for negotiations

7.1 The timeframes for negotiation of provision of a *negotiated distribution service* in Table 1 or agreed between the parties are suspended if:

(a) a dispute in relation to the *negotiated distribution service* is notified to the Australian Energy Regulator (**AER**) under Part 10 of the National Electricity Law (**NEL**), from the date of the notification of that dispute to the AER until:

- the withdrawal of the dispute under section 126 of the NEL;
- the termination of the dispute by the AER under section 131 or section 132 of the NEL; or
- a determination is made in respect of the dispute by the AER in accordance with section 128 of the NEL;

(b) after 15 business days of Powercor Australia requesting commercial information under clause 4.1, or, where an alternative timeframe for the provision of the commercial information has been agreed pursuant to clause 4.3, after 5 business days after the date agreed for the provision of the requested commercial information, the *Service Applicant* has not provided that information;

(c) after 15 business days of providing the application to Powercor Australia, the *Service Applicant* fails to provide the information commercial information set out in clause 4.4;

(d) the *Service Applicant* fails to pay the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service* in accordance with clause 10, from the next business day after the amount is due until such time as the *Service Applicant* has paid the outstanding amount; and/or

(e) where Powercor Australia has been required to notify and consult with any affected *Distribution Network Users* in accordance with clause 5.2, from the date of the notification to the affected *Distribution Network User* until the end of the time limit specified by Powercor Australia for any affected *Distribution Network Users* to provide to Powercor Australia information regarding the impact of the provision of the *negotiated distribution service*, or the date on which Powercor Australia receives such information from the affected *Distribution Network Users,* whichever is the later.

7.2 Each party will notify the other party if it considers that the timeframe has been suspended, within 5 business days of the date that the party considers the suspension took effect.

8 Publication of the results of negotiations

8.1 Powercor Australia will publish on its website the results of negotiations for access to a *negotiated distribution service*.

9 Dispute resolution

9.1 All disputes as to the *terms and conditions of access* for the provision of *negotiated distribution services* are to be dealt with in accordance with Part 10 of the NEL and Part L of Chapter 6 of the NER.

10 Payment of Powercor Australia's reasonable direct expenses

10.1 From time to time, Powercor Australia may give the *Service Applicant* a notice setting out the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service*.

10.2 The *Service Applicant* must, within 20 business days of the notice given pursuant to clause 10.1, pay to Powercor Australia the amount set out in the notice in the manner set out in the notice.

10.3 If the *Service Applicant* fails to pay any sum due for payment under this clause 10 on the due date, the *Service Applicant* must pay interest on that sum from the due date until the date of actual payment at the Default Rate. Interest is to be calculated on a daily basis and capitalised monthly.

11 Termination of negotiations

11.1 The *Service Applicant* may elect not to continue with its application for a *negotiated distribution service* and may terminate negotiations by giving Powercor Australia written notice of its decision to do so.

11.2 Powercor Australia may terminate negotiations under this *negotiating framework* by giving the *Service Applicant* written notice of its decision to do so where:

(a) Powercor Australia believes on reasonable grounds that the *Service Applicant* is not conducting the negotiations under this *negotiating framework* in good faith;

(b) after 30 business days from the date of a notice issued under clause 10.1, the *Service Applicant* has failed to pay to Powercor Australia the amount set out in the notice;

(c) there are multiple or recurring failures by the *Service Applicant* to comply with the requirements of the *negotiating framework*;

(d) the *Service Applicant* fails to comply with an obligation in this *negotiating framework* to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action to the reasonable satisfaction of Powercor Australia within 20 business days of a written request from Powercor Australia; or

(e) a Solvency Default occurs in relation to the *Service Applicant.*

11.3 For the avoidance of doubt, in the event negotiations are terminated pursuant to this clause 11:

(a) Powercor Australia may nonetheless give notice under clause 10.1 for the recovery of the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service* and the *Service Applicant* must pay the amount set out in the notice in accordance with clause 10.2, along with any applicable interest payable under clause 10.3; and

(b) A party must return all commercial information provided to it by or on behalf of the other party in respect of this *negotiating framework* or, if requested by the other party, destroy all copies of the commercial information in its possession or control, in either case within 5 business days' of request.

12 GST

12.1 Any reference to costs, expenses, consideration and other amounts in this *negotiating framework* or provided under or in connection with it are exclusive of GST, unless expressed to be GST-inclusive.

12.2 Where Powercor Australia makes a taxable supply to the *Service Applicant* under or in connection with this *negotiating framework*, the *Service Applicant* must pay to Powercor Australia an additional amount equal to the GST payable on the supply (unless the consideration for that taxable supply is expressed to include GST). The additional amount must be paid by the *Service Applicant* at the later of the following:

12.2.1 The date when any consideration for the taxable supply is first paid or provided.

12.2.2 The date when Powercor Australia issues a tax invoice to the *Service Applicant*.

12.3 If, under or in connection with this *negotiating framework*, Powercor Australia has an adjustment for a supply under the GST Act which varies the amount of GST payable by Powercor Australia, Powercor Australia will adjust the amount payable by the *Service Applicant* to take account of the varied GST amount. Powercor Australia must issue an adjustment note to the *Service Applicant* within 28 days of becoming aware of the adjustment.

12.4 If a party is entitled to be reimbursed or indemnified under or in connection with this *negotiating framework*, the amount to be reimbursed or indemnified is reduced by the amount of GST for which there is an entitlement to claim an input tax credit on an acquisition associated with the reimbursement or indemnity. The reduction is to be made before any increase under clause 12.2. An entity is assumed to be entitled to a full input tax credit on an acquisition associated with the reimbursement or indemnity unless it demonstrates otherwise before the date the reimbursement or indemnity is made.

12.5 This clause 12 will not merge on completion and will survive the termination of this document by any party (including for the avoidance of doubt termination of negotiations under this *negotiating framework*).

12.6 Terms used in this clause that are not otherwise defined in this *negotiating framework* have the meanings given to them in the GST Act.

13 Notices

Giving notices

13.1 Any notice or communication given to Powercor Australia under this *negotiating framework* is only given if it is in writing and sent in one of the following ways:

(a) delivered or posted to Powercor Australia at its address and marked for the attention of the relevant officer set out below;

(b) faxed to Powercor Australia at its fax number and marked for the attention of the relevant officer set out below.

Name:	Powercor Australia Pty
Address:	Locked Bag 14090 Melbourne 8001
Fax number:	9683-4499
Attention:	Manager Customer Connections

13.2 Any notice, consent, information or request given or made under this document is only given or made to the *Service Applicant* if it is in writing and delivered to the *Service Applicant* at the address or fax number specified in the *Service Applicant*'s application and marked for the attention of the relevant officer specified in the application.

Change of address or facsimile number

13.3 If a party gives the other party three business days notice of a change of its address or facsimile number, any notice or communication is only given by that other party if it is delivered, posted or faxed to the latest address or fax number.

Time notices are given

13.4 Any notice or communication is to be treated as given at the following time:

(a) if it is delivered, when it is left at the relevant address;

(b) if it is sent by post, two business days after it is posted;

(c) if it is sent by fax, as soon as the sender receives from the sender's fax machine a report of an error free transmission to the correct fax number.

13.5 However, if any notice or communication is given, on a day that is not a business day or after 5pm on a business day, in the place of the party to whom it is sent it is to be treated as having been given at the beginning of the next business day.

14 Miscellaneous

Governing law and jurisdiction

14.1 This document is governed by the law of Victoria. The parties submit to the non-exclusive jurisdiction of its courts and courts of appeal from them. The parties will not object to the exercise of jurisdiction by those courts on any basis.

Rights cumulative

14.2 The rights and remedies of a party under this document are in addition to and do not replace or limit any other rights or remedies that the party may have.

Severability

14.3 Each provision of this document is individually severable. If any provision is or becomes illegal, unenforceable or invalid in any jurisdiction it is to be treated as being severed from this document in the relevant jurisdiction, but the rest of this document will not be affected. The legality, validity and enforceability of the provision in any other jurisdiction will not be affected.

Interpretation

14.4 In this document the following definitions apply:

Bill Rate means the 90 day bank bill swap reference rate (source: Bloomberg) as quoted in the Australian Financial Review (or some equivalent rate if quotation or the rate ceases) on the first business day following the due date.

Powercor Australia means Powercor Australia Pty (ABN 76 064 651 056) of 40 Market Street Melbourne 8001.

Control means, in relation to an entity, the power to directly or indirectly:

(a) control the membership of the board of directors or other governing body of the entity;

(b) control the entity applying section 50AA of the Corporations Act 2001;

(c) where the entity is trustee of a trust, to appoint, remove or replace the trustee or direct the trustee as to decisions to be made in relation to the trust; or

(d) direct the management and policies of that entity, whether by means of trusts, agreements, arrangements, undertakings, practices, the ownership of any interest in shares or in any other way.

Default Rate means the Bill Rate applicable at the time of the default plus 4%.

GST Act means *A New Tax System (Goods and Services Tax) Act 1999* (Cth).

Solvency Default means the occurrence of any of the following events in relation to the *Service Applicant*:

(a) A step being taken to wind up the *Service Applicant*;

(b) A receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the *Service Applicant*, or a provisional liquidator is appointed to the *Service Applicant*;

(c) A mortgagee, charge or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the *Service Applicant*;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The *Service Applicant* stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The *Service Applicant* applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the *Service Applicant* or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the *Service Applicant's* property;

(h) The *Service Applicant* takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the *Service Applicant* or any part of its property;

(i) Except to reconstruct or amalgamate while solvent, the *Service Applicant* enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the *Service Applicant's* affairs;

(j) The *Service Applicant* is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001;

(k) The *Service Applicant* ceases or threatens to cease to carry on its main business;

(l) Anything analogous or having substantially similar effect to any of the events specified above happens in relation to the *Service Applicant*;

(m) Anything else occurs that reasonably indicates that there is a significant risk that the *Service Applicant* is or will become unable to pay its debts as they fall due; or

(n) Any of the above happens to an entity that Controls the *Service Applicant.*

14.5 In the interpretation of this document, the following provisions apply unless the context otherwise requires:

(a) In this *negotiating framework* the words in italics have the meaning given to them in the NEL and the NER.

(b) Headings are inserted for convenience only and do not affect the interpretation of this document.

(c) A reference in this document to a business day means a day other than a Saturday or Sunday on which banks are open for business generally in Melbourne, Victoria.

(d) If the day on which any act, matter or thing is to be done under this document is not a business day, the act, matter or thing must be done on the next business day.

(e) A reference in this document to any law, legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision.

(f) A reference in this document to any document or agreement is to that document or agreement as amended, novated, supplemented or replaced.

(g) Unless otherwise stated, a reference to a clause, part, schedule or attachment is a reference to a clause, part, schedule or attachment of or to this document.

(h) An expression importing a natural person includes any company, trust, partnership, joint venture, association, body corporate or governmental agency.

(i) Where a word or phrase is given a defined meaning, another part of speech or other grammatical form in respect of that word or phrase has a corresponding meaning.

(j) A word which indicates the singular also indicates the plural, a word which indicates the plural also indicates the singular, and a reference to any gender also indicates the other gender.

(k) A reference to the word 'include' or 'including' is to be interpreted without limitation.

Jemena Electricity Networks (Vic) Ltd Revised Regulatory Proposal 2011-2015

Appendix 3.2

Negotiating framework (clean copy)

20 July 2010

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1 Application of negotiating framework

A number of JEN's services are classified as Negotiated Distribution Services for which JEN must negotiate in good faith with Service Applicants to provide the services on fair and reasonable terms.

This document sets out JEN's negotiating framework for this purpose.

1.1 Who the negotiating framework applies to

This negotiating framework applies to JEN and each Service Applicant who has applied in writing to JEN for the provision of a Negotiated Distribution Service.

1.2 Obligation to comply

JEN and any Service Applicant who wishes to receive a Negotiated Distribution Service from JEN must comply with the requirements of this negotiating framework.

1.3 Interaction with other regulatory instruments

The requirements set out in this negotiating framework are in addition to any requirements or obligations contained in the Rules or a relevant Victorian Regulatory Instrument.

In the case of inconsistency between the Rules or a relevant Victorian Regulatory Instrument and this negotiating framework, the Rules or the relevant Victorian Regulatory Instrument will prevail.

1.4 No obligation to provide service

Nothing in this negotiating framework or in the Rules will be taken to impose an obligation on JEN to provide any service to the Service Applicant.

1.5 Obligation to negotiate in good faith

JEN and the Service Applicant must negotiate the terms and conditions of access for the provision by JEN of the Negotiated Distribution Service sought by the Service Applicant in good faith.

2 Timeframes

2.1 Commencing, progressing and finalising negotiations

2.1.1 Subject to paragraphs 2.1.2 to 2.1.4, following a request for a Negotiated Distribution Service, JEN and the Service Applicant will use their reasonable endeavours to:

A agree the milestones, information requirements and any other relevant issues within 5 Business Days of receipt by JEN of the application;

B adhere to any timetable established for negotiations, and progress negotiations in an expeditious manner; and

C finalise negotiations within 120 Business Days of the initial application.

2.1.2 JEN and the Service Applicant must use reasonable endeavours to adhere to the timeframes set out in paragraph 2.1.3 or agreed pursuant to paragraph 2.1.4 during the negotiation for the supply of a Negotiated Distribution Service.

2.1.3 The timeframes for negotiating Negotiated Distribution Services are set out in Table 2-1, together with a reference to other relevant paragraphs of this negotiating framework.

Table 2-1: Timeframe for negotiating negotiated distribution services

Event	References	Timeframe	
A	Receipt of written application for a Negotiated Distribution Service.	1.1	**X**
B	Parties discuss: • the nature of the services required; • any Commercial Information to be provided by the Service Applicant; and • notification and consultation with affected Distribution Network Users and AEMO [Note – These discussions may occur by electronic communication or by telephone, if appropriate.] Parties agree: • timeframes for negotiation and consultation; and • milestones. Service Applicant pays application fee.	2.1.1, 2.2, 3, 6, 7	X + 5 Business Days
C	Service Applicant provides Commercial Information to JEN. *[Note – JEN may request additional Commercial Information if required, and if so, the Service Applicant must provide additional Commercial Information to JEN.]*	3	X + 20 Business Days [Additional 20 Business Days]
D	Where required, JEN consults with affected Distribution Network Users and AEMO	6	X + 40 Business Days

Event		References	Timeframe
E	All necessary information is received by JEN, including: • the completed application; • the Service Applicant's Commercial Information; and • consultation feedback where required. The Service Applicant has paid the relevant fee.	1.1, 3, 7	**Y**
F	JEN provides Commercial Information and makes Negotiated Distribution Service offer.	4,5	Y + 65 Business Days for Embedded Generator Services. Y + 20 Business Days for other Negotiated Distribution Services.
G	Parties finalise negotiations.	2.1.1	Y + 80 Business Days

2.1.4 The timeframes set out in paragraph 2.1.3 may be modified from time to time by agreement between the parties, where each party's agreement must not be unreasonably withheld. Any such amended negotiating timeframe will be taken to be a reasonable period of time for commencing, progressing and finalising negotiations with a Service Applicant for the provision of the Negotiated Distribution Services.

2.2 Suspension of timeframes

2.2.1 The timeframes for negotiation of the provision of a Negotiated Distribution Service set out in paragraph 2.1.3 or agreed pursuant to paragraph 2.1.4 are suspended as follows:

A the obligations of both parties are suspended if a dispute in relation to the Negotiated Distribution Service has been notified to JEN or the Service Applicant (as applicable) in accordance with paragraph 10. The timeframes are suspended from the date of that notification until the date of the withdrawal of the dispute or resolution of the dispute under paragraph 10;

B JEN's obligations are suspended if the Service Applicant has not supplied additional Commercial Information requested by JEN pursuant to paragraph 3.2 within 20 Business Days of that request or the Service Applicant does not otherwise comply with a relevant requirement of the timeframes set out in paragraph 2.1.3 or agreed pursuant to paragraph 2.1.4.

3 Provision of commercial information by service applicant

3.1 Obligation to provide commercial information

3.1.1 JEN may request the Service Applicant to provide JEN with Commercial Information held by the Service Applicant that JEN reasonably requires to enable it to engage in effective negotiations with the Service Applicant in relation to the Service Applicant's application.

3.1.2 Subject to paragraph 2.2, the Service Applicant must use its reasonable endeavours to provide JEN the Commercial Information requested by JEN within 10 Business Days of that request, or within such other period as agreed by the parties.

3.2 Obligation to provide additional commercial information

3.2.1 JEN may request the Service Applicant to provide JEN with any additional Commercial Information that is reasonably required by JEN to enable it to engage in effective negotiations with the Service Applicant in relation to the Service Applicant's application or to clarify any Commercial Information provided pursuant to paragraph 3.1.

3.2.2 Subject to paragraph 2.2, the Service Applicant must use its reasonable endeavours to provide JEN the Commercial Information requested by JEN in accordance with paragraph 3.2.1 within 10 Business Days of the date of the request, or within such other period as agreed by the parties.

3.3 Confidentiality requirements

3.3.1 Commercial Information provided to JEN by the Service Applicant may be provided subject to the condition that JEN must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure or as required by law. The Service Applicant may require JEN to enter into a confidentiality agreement with the Service Applicant in respect of Commercial Information provided by the Service Applicant to JEN. The terms of the confidentiality agreement must be reasonably acceptable to both parties.

3.3.2 A consent provided by the Service Applicant in accordance with paragraph 3.3.1 may be given subject to the condition that the person to whom JEN discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

4 Provision of commercial information by JEN

4.1 Obligation to provide commercial information (including cost information)

4.1.1 JEN will provide the Service Applicant with all Commercial Information held by JEN that is reasonably required by the Service Applicant to enable it to engage in effective negotiations with JEN for the provision of the Negotiated Distribution Service sought by the Service Applicant.

4.1.2 The information will be provided within a timeframe agreed by the parties, but in any case prior to or contemporaneous with the provision of the Negotiated Distribution Service offer, and will include the following information:

A a description of the nature of the Negotiated Distribution Service, including what JEN would provide to the Service Applicant as part of that service;

B the terms and conditions on which JEN would provide the Negotiated Distribution Service to the Service Applicant; and

C an explanation of the costs and/or the increase or decrease in costs (as appropriate) associated with providing the Negotiated Distribution Service to the Service Applicant. The purpose of this explanation is to demonstrate that the charges reflect the costs and/or cost increment or decrement (as appropriate) of providing the Negotiated Distribution Service.

4.1.3 For the purpose of paragraph 4.1.2C, JEN will have appropriate arrangements to assess and review charges and the basis on which they are made.

4.2 Confidentiality requirements

4.2.1 Commercial Information provided by JEN in accordance with paragraph 4.1 may be provided subject to the condition that the Service Applicant must not disclose the Commercial Information to any other person unless JEN consents in writing to the disclosure or as required by law. JEN may require the Service Applicant to enter into a confidentiality agreement with JEN in respect of Commercial Information provided by JEN to the Service Applicant. The terms of the confidentiality agreement must be reasonably acceptable to both parties.

4.2.2 A consent provided by JEN to a Service Applicant in accordance with paragraph 4.2.1 may be given subject to the condition that the person to whom the Service Applicant discloses the Commercial Information must enter into a separate confidentiality agreement with JEN.

5 Pricing principles

JEN will comply with the Negotiated Distribution Service Principles set out in clause 6.7.1 of the Rules.

6 Consultation with affected parties

6.1 JEN to determine potential impact on Distribution Network Users

JEN will determine the potential impact on Distribution Network Users, other than the Service Applicant, of the provision of the Negotiated Distribution Service.

6.2 JEN to notify and consult

JEN will notify and consult with any affected Distribution Network Users and ensure that the provision of the Negotiated Distribution Service does not result in non-compliance with obligations in relation to other Distribution Network Users under the Rules.

7 Payment of JEN's Costs

7.1 Application fee

7.1.1 Prior to commencing negotiations, the Service Applicant must pay an application fee to JEN.

7.1.2 The application fee will be determined by JEN based upon an estimate of the minimum reasonable direct Costs that will be incurred by JEN in relation to the Service Applicant's application for the provision of the Negotiated Distribution Service.

7.2 Direct Costs

7.2.1 From time to time, JEN may give the Service Applicant a notice setting out an estimate of any reasonable direct Costs that will be incurred by JEN in relation to the Service Applicant's application for the provision of the Negotiated Distribution Service that exceed the application fee paid by the Service Applicant under paragraph 7.1.2

7.2.2 The Service Applicant must, within 20 Business Days of the receipt of that notice, pay to Jemena the amount stated in the notice provided by JEN under paragraph 7.2.1.

7.2.3 If the aggregate direct Costs incurred by JEN in relation to the Service Applicant's application for the provision of the Negotiated Distribution Service are less than the amount paid by the Service Applicant under paragraphs 7.1.1 and 7.2.2, JEN will:

A offset the excess amount against the price for the Negotiated Distribution Service; or

B refund the excess amount if the Service Applicant does not acquire the Negotiated Distribution Service.

7.2.4 JEN may require the Service Applicant to enter into a binding agreement addressing conditions, guarantees and other matters in relation to the payment of on-going Costs in accordance with this paragraph 7.

8 Termination of negotiations

8.1 Termination by Service Applicant

The Service Applicant may elect not to continue with its application for a Negotiated Distribution Service and may terminate the negotiations by giving JEN written notice of its decision to do so.

8.2 Termination by JEN

JEN may terminate a negotiation under this negotiating framework by giving the Service Applicant written notice of its decision to do so where:

8.2.1 JEN believes on reasonable grounds that the Service Applicant is not conducting the negotiation under this negotiating framework in good faith;

8.2.2 JEN reasonably believes that the Service Applicant will not acquire any Negotiated Distribution Service; or

8.2.3 an act of Solvency Default occurs in relation to the Service Applicant.

9 Publication of results of negotiation

9.1 JEN to publish results

At the conclusion of the negotiations between JEN and the Service Applicant, whether by way of agreed outcome or termination pursuant to paragraph 8 of this negotiating framework, JEN will publish the results of the negotiations on its website.

9.2 Form of publication

JEN will publish the results described in paragraph 9.1 in a quarterly summary on its website.

10 Dispute resolution

All disputes between the parties as to the terms and conditions of access for the provision of a Negotiated Distribution Service will be dealt with in accordance with the National Electricity Law and Chapter 8 of the Rules.

11 Giving notices

11.1 Address for notices

Except as otherwise indicated in this negotiating framework, a notice, consent, information, application or request that must or may be given or made to a party under this negotiating framework is only given or made if it is in writing and delivered or posted to that party at its address set out below.

If a party gives the other party 5 Business Days' notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered or posted to the other party's most recent address.

JEN

Name: Jemena Electricity Networks (Vic) Ltd

Address: 321 Ferntree Gully Road, Mount Waverley 3149

PO Box: Locked Bag 7000, Mount Waverley 3149

Fax: ***[To be completed]***

Email: ***[To be completed]***

Service Applicant

Name: Service Applicant

Address: The nominated address of the Service Applicant provided in writing to JEN as part of the application

11.2 Time notice is given

11.2.1 A notice, consent, information, application or request is to be treated as given or made at the following time:

- if it is delivered, when it is left at the relevant address;
- if it is sent by post, 2 Business Days after it is posted;
- if it is sent by fax, on receipt by the sender of a transmission control report from the despatching machine showing the relevant number of pages and the correct destination machine number or name of recipient and indicating that the transmission has been made without error; or
- if sent by email once acknowledged as received by the addressee.

11.2.2 If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next Business Day.

12 Terms & abbreviations

12.1 Definitions

In this document the following definitions apply.

Table 12-1: Definitions

Term	Definition
Business Day	A day on which all banks are open for business generally in Melbourne, Victoria.
Commercial Information	Includes, but is not limited to, the following classes of information: • details of corporate structure; • financial details relevant to creditworthiness and commercial risk; • ownership of assets; • technical information relevant to the application for the Negotiated Distribution Service; • financial information relevant to the application for the Negotiated Distribution Service; • details of an application's compliance with any law, standard, Rules or guideline, but does not include: • confidential information provided by another person to either: – the Service Applicant; or – JEN; • information that the Service Applicant is prohibited, by law, from disclosing to JEN; or • information that JEN is prohibited, by law, from disclosing to the Service Applicant.
Costs	Any costs or expenses incurred by JEN in complying with this negotiating framework or otherwise advancing the Service Applicant's request for the provision of a Negotiated Distribution Service.
Embedded Generator	A generation system consisting of one or more generation units that is, or that is to become, connected to the distribution system.
Embedded Generator Services	Services associated with the connection of Embedded Generators to JEN's Distribution Network.
JEN	Jemena Electricity Networks (Vic) Ltd, ABN 82 064 651 083
National Electricity Law	The National Electricity Law set out in the schedule to the *National Electricity (South Australia) Act 1996* of South Australia, having force and effect as a law of Victoria pursuant to section 6 of the *National Electricity (Victoria) Act 2005*.
Negotiated Distribution Services	• Embedded Generator Services; and • Public Lighting Services.
Public Lighting Services	Services associated with: • installing new public lighting assets; or • altering and relocating JEN's existing public lighting assets.

Term	Definition
Rules	The National Electricity Rules made under the National Electricity Law.
Solvency Default	The occurrence of any of the following events in relation to the Service Applicant: (a) an originating process or application for the winding up of the Service Applicant (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the Service Applicant, and is not dismissed before the expiration of 60 days from service on the Service Applicant; (b) a receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the Service Applicant, or a provisional liquidator is appointed to the Service Applicant; (c) a mortgagee, chargee or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the Service Applicant; (d) a mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition; (e) the Service Applicant stops payment of, or admits in writing its inability to pay, its debts as they fall due; (f) the Service Applicant applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the Service Applicant or any of its property; (g) a court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the Service Applicant's property; (h) the Service Applicant takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the Service Applicant; (i) a controller (as defined in the Corporations Act 2001) is appointed in respect of any part of the property of the Service Applicant; (j) except to reconstruct or amalgamate while solvent, the Service Applicant enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the Service Applicant's affairs; (k) the Service Applicant is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001; or (l) anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the Service Applicant.
Victorian Regulatory Instrument	An Act, licence, code, guideline or other regulatory instrument to which JEN is subject under Victorian law. As at the date this negotiating framework is established, Victorian Regulatory Instruments include without limitation: • Electricity Industry Guideline No. 14, Provision of Services by Electricity Distributors, April 2004 • Electricity Industry Guideline No. 15, Connection of Embedded Generation, August 2004; and • Public Lighting Code

12.2 Interpretation

In this negotiating framework, unless the context otherwise requires:

- terms defined in the Rules have the same meaning in this negotiating framework;
- a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;
- a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;
- a reference to a paragraph, part, schedule or attachment is a reference to a paragraph, part, schedule or attachment of or to this document unless otherwise stated;
- an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and
- a covenant or agreement on the part of two or more persons binds them jointly and severally

EDPR 2011-2015

Proposed Negotiating Framework for Negotiated Services

Version number:	Version 2.0
Status:	Final
Date published:	12 July 2010
File name:	Proposed Negotiating Framework Final

Authorised by:	**Signature:**	**Date:**
Alistair Parker Director, Regulation & Network Strategy		12 July 2010

SP AusNet
A member of Singapore Power Group

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Negotiating Framework

The National Electricity Rules (the Rules) require certain distribution services (*negotiated distribution services*) to be provided on terms and conditions of access that are negotiated between the *Distribution Network Service Provider* (DNSP) and *Service Applicants*. Pursuant to rule 6.7.5(a) SPI Electricity has prepared a *negotiating framework* which sets out the procedures to be followed during negotiations. The *negotiating framework* must be consistent with:

- the applicable requirements of the relevant distribution determination; and
- the minimum requirements for a *negotiating framework* specified in rule 6.7.5(c).

SPI Electricity may seek to amend or replace its *negotiating framework* at the time it submits its proposal for the next regulatory control period, by submitting a new proposed negotiating framework in accordance with the Rules as in force at that time.

1 Application of Negotiating Framework

This *negotiating framework* applies to SPI Electricity and each and every *Service Applicant* who has made an application in writing for the provision of *negotiated distribution services*.

The requirements of this *negotiating framework* are in addition to any requirements or obligations contained in the Rules. In the case of any inconsistency between this *negotiating framework* and the Rules, the Rules will prevail.

Notwithstanding this *negotiating framework*, in the event there is any inconsistency with any of the requirements of:

(1) rules 5.3 and 5.5 insofar as the *negotiating framework* applies to *negotiated distribution services* which would have been *negotiated distribution service* regardless of the operation or clause 6.24.2(c); and

(2) rules 5.3 and 5.4A insofar as the *negotiating framework* applies to *negotiated distribution services* which would have been treated as *negotiated transmission services* were it not for the operation of clause 6.24.2(c),

and any other relevant provision of Chapter 6, the requirements of rules 5.3, 5.4A and 5.5 will prevail.

2 Commencement of Negotiations

A *Service Applicant* who wishes to receive a *negotiated distribution service* from SPI Electricity must submit a written request to the SPI Electricity customer service centre. The request may be made on the SPI Electricity application form for electricity supply requests or may be made by written request. The request must elect to conduct a negotiation under this *negotiating framework*.

3 Application for Negotiated Distribution Services

On receipt of an application form or written request (as applicable), SPI Electricity and the *Service Applicant* will proceed to negotiate in good faith the terms and conditions of access in accordance with this *negotiation framework*.

Timeframe for Negotiation

In accordance with the Rules, SPI Electricity will make an offer to the *Service Applicant* to provide the *negotiated distribution service*, within 20 *Business Days* of receipt of the request.

If the request does not comply with the requirements of the Rules or this *negotiating framework* SPI Electricity will make an offer to the *Service Applicant* to provide the *negotiated distribution service* within 20 *Business Days* of the date when SPI Electricity receives all commercial information or information which SPI Electricity deems reasonably necessary to provide the offer.

SPI Electricity may refuse to make an offer to the *Service Applicant* to provide the *negotiated distribution service* if:

(a) SPI Electricity has already made an offer in response to an earlier request for that *negotiated distribution service* and the offer has not been accepted;

(b) SPI Electricity is of the reasonable opinion that the *Service Applicant* is not conducting the negotiations in good faith; or

(c) SPI Electricity is permitted or required to do so by any electricity industry code, guideline or standard, or any applicable law.

The offer made to the *Service Applicant* will contain the price and terms and conditions for provision of the *negotiated distribution service*, including the following (as applicable):

(a) a description of the *connection* assets;

(b) the amount of the *Service Applicant's* capital contribution for new works and augmentation;

(c) the costs SPI Electricity will incur to provide relevant services;

(d) a requirement that the *Service Applicant* comply with the provisions of any electricity industry code, guideline or standard, unless otherwise agreed by the SPI Electricity and the *Service Applicant* (both of whom in that respect must act reasonably).

In preparing an offer to provide the *negotiated distribution service*, SPI Electricity will comply with the Pricing Principles, to the extent that those principles apply to the relevant *negotiated distribution service*.

An offer made for provision of the *negotiated distribution service* will remain valid for a period of 60 *Business Days* from the date of issue of the offer. Within those 60 *Business Days* the *Service Applicant* must notify SPI Electricity if:

(a) it accepts the offer;

(b) it rejects the offer and does not wish to commence with negotiations for provision of the *negotiated distribution service*; or

(c) it rejects the offer but does wish to commence with negotiations for provision of the *negotiated distribution service*.

If the *Service Applicant* notifies SPI Electricity that it rejects SPI Electricity's offer in accordance with sub-clause (c) above then:

(a) SPI Electricity may request further information from the *Service Applicant* in order to determine a negotiation program reasonably acceptable to both parties; and

(b) SPI Electricity will finalise negotiations in accordance with that plan.

The timescales are summarised in Table 1.

Table 1

Event	**Indicative Timeframe**
Service Applicant provides all information to SPI Electricity	20 Business Days
Parties finalise negotiations	60 Business Days

Suspension of Timeframe

The timeframes indicated above for the provision of a *negotiated distribution service* may be suspended at the discretion of SPI Electricity in the event that:

(a) a dispute is raised in relation to the *negotiated distribution service* being provided;

(b) a dispute is raised in relation to this *negotiating framework*; or

(c) SPI Electricity determines in its reasonable opinion that insufficient information has been provided by the *Service Applicant*.

The timeframe will remain suspended until:

(a) the dispute is resolved;

(b) the dispute is abandoned; or

(c) the information is provided,
(as applicable).

Fees for Offer and Costs of Negotiated Distribution Service

Prior to commencing negotiations, the *Service Applicant* must pay to SPI Electricity an application fee. The application fee will be SPI Electricity's reasonable estimate of the direct costs that will be incurred by SPI Electricity in processing the application.

SPI Electricity may also require the *Service Applicant* to enter into an agreement addressing the payment of the costs associated with the processing of the offer to provide the *negotiated distribution services*.

Termination of Negotiation

SPI may terminate a negotiation under this *negotiating framework* by giving the *Service Applicant* written notice of its intention to so where:

(a) SPI Electricity is of the reasonable opinion that the *Service Applicant* will not acquire the *negotiated distribution service*;

(b) SPI Electricity believes on reasonable grounds that the *Service Applicant* is not conducting the negotiations in good faith;

(c) the *Service Applicant* fails to comply with the obligations in this *negotiating framework*;

(d) the *Service Applicant* fails to pay the fees specified in this clause 3; or

(e) an Insolvency Event occurs in respect of the *Service Applicant*.

Results of Negotiation

At the conclusion of the negotiations between SPI Electricity and the *Service Applicant*, (regardless of whether the outcome is agreed or terminated) SPI Electricity will publish the results of the negotiations on its website.

4 Provision of Information

Following a request from a *Service Applicant* to receive a *negotiated distribution service*, SPI Electricity may request all commercial information reasonably required by SPI Electricity to enable SPI Electricity to assess the application and negotiate the requested services.

Commercial information for the purposes of this *negotiating framework* will include, but not be limited to:

- information in relation to a companies corporate structure;
- financial information;
- asset ownership; and
- details of the *Service Applicants* compliance with any law, standard, guidelines or the Rules.

Commercial information to be provided by a *Service Applicant* does not include *confidential information* provided to SPI Electricity by another person.

Following a request from SPI Electricity the *Service Applicant* must use reasonable endeavours to provide the requested commercial information within 10 *Business Days* of the request being issued, or within the time period nominated by SPI Electricity being not less than 10 *Business Days*.

SPI Electricity will not disclose commercial information to any other person unless authorised by the *Service Applicant* to do so. The *Service Applicant* may require SPI Electricity to enter into a confidentiality agreement in respect to the provision of that commercial information requested. The terms of the confidentiality agreement must be reasonably acceptable to both parties.

Following a request from the *Service Applicant*, SPI Electricity will:

(i) identify and inform a *Service Applicant* of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the *negotiated distribution service*;

(ii) demonstrate to a *Service Applicant* that the charges for providing the *negotiated distribution service* reflect those costs and/or the cost increment or decrement (as appropriate); and

(iii) have appropriate arrangements for assessment and review of the charges and the basis on which they are made.

SPI Electricity will provide commercial information to the *Service Applicant*. SPI Electricity may impose conditions on the provision of that commercial information, including but not limited to, the condition that the *Service Applicant* must not disclose the commercial information to any other person unless SPI Electricity consents in writing. SPI Electricity may require the *Service Applicant* to enter into a confidentiality agreement prior to the release of the information. The terms and conditions of the confidentiality agreement must be reasonably acceptable to both parties.

The information provided to the *Service Applicant* in accordance with this clause may be subject to the condition that the person to whom the *Service Applicant* discloses the information must enter into a separate confidentiality agreement with SPI Electricity.

5 Determination of Impact on Other Distribution Users

In accordance with rule 6.7.5 (c) (8), SPI Electricity will determine the potential impact on other distribution network users of the provision of the *negotiated distribution service*.

If there is a potential impact determined SPI Electricity will notify and consult with any affected distribution network user and take reasonable steps to ensure that the provision of the *negotiated distribution service* does not result in non-compliance with obligations to other distribution network users in accordance with the Rules.

If SPI Electricity is required to consult pursuant to this clause 5, the timeframe provided for in clause 3 shall be suspended until the information required to assess the impact is received from the affected distribution network user.

6 Dispute Resolution

By entering into the negotiation process, SPI Electricity and the *Service Applicant* agree that a dispute will be dealt with in accordance with SPI Electricity's dispute resolution process in the first instance.

In the event that dispute resolution process provides unsuccessful, disputes arising during the course of the negotiation shall be dealt with in accordance with the *National Electricity Law* and Chapter 8 of the Rules.

7 Notices

Each communication (including each notice, consent, approval, request and demand) under or in connection with this *negotiating framework* to SPI Electricity must be addressed as follows (or as otherwise notified by SPI Electricity from time to time):

To SPI Electricity:

Address:	8 Beaconsfield Avenue Beaconsfield Victoria 3807
Fax:	03 9238 6447
For the attention of:	The Customer Service Centre

unless otherwise agreed by SPI Electricity.

Each communication must also:

(a) be signed by the *Service Applicant* making it or (on the *Service Applicant*'s behalf) by the solicitor for, or any attorney, director, secretary or authorised agent of, the *Service Applicant*;

(b) be delivered by hand or posted by prepaid post to the address, or sent by fax to the number listed above; and

is taken to be received by SPI Electricity:

(a) in the case of prepaid post on the third day after the date of posting;

(b) (in the case of fax) at the time in the place to which it is sent equivalent to the time shown on the transmission confirmation report produced by the fax machine from which it was sent; and

(c) (in the case of delivery by hand) on delivery, but if the communication is taken to be received on a day that is not a *Business Day* or after 5.00 pm, it is taken to be received at 9.00 am on the next *Business Day*.

8 Definitions and Interpretation

In this negotiating framework words in italics have the same meaning as given to those words under the Rules. Capitalised words are defined as follows:

"Insolvency Event" means the occurrence of any of the following events in relation to the *Service Applicant*:

(a) a "controller" (as defined in section 9 of the Corporations Act), manager, trustee, administrator, or similar officer is appointed in respect of the *Service Applicant*;

(b) a liquidator or provisional liquidator is appointed in respect of the *Service Applicant*;

(c) any application (not being an application withdrawn or dismissed within 7 days) is made to a court for an order, or an order is made, or a meeting is convened, or a resolution is passed, for the purpose of:

(i) appointing a person referred to in paragraphs (a) or (b);
(ii) winding up the *Service Applicant*; or
(iii) proposing or implementing a scheme of arrangement;

(d) any event or conduct occurs which would enable a court to grant a petition, or an order is made, for the bankruptcy of the *Service Applicant* or the *Service Applicant* 's estate under any insolvency provision;

(e) a moratorium of any debts of the *Service Applicant* , a personal insolvency agreement or any other assignment, composition or arrangement (formal or informal) with the *Service Applicant* 's creditors or any similar proceeding or arrangement by which the assets of the *Service Applicant* are subjected conditionally or unconditionally to the control of the *Service Applicant* 's creditors or a trustee, is ordered, declared or agreed to, or is applied for and the application is not withdrawn or dismissed within 7 days;

(f) the *Service Applicant* becomes, or admits in writing that it is, is declared to be, or is deemed under any applicable law to be, insolvent or unable to pay its debts; or

(g) any writ of execution, garnishee order, mareva injunction or similar order, attachment, distress or other process is made, levied or issued against or in relation to any asset of the *Service Applicant*.

"Pricing Principles" means the *Negotiated Distribution Service Principles* set out in rule 6.7.1 of the Rules.

Proposed Negotiating Framework January 2011 – December 2015

United Energy Distribution
501 Blackburn Road
Mt Waverley 3149

1 Preamble

(a) This Negotiating Framework set outs the procedure to be followed by *United Energy* and a person (the *Service Applicant*) who wishes to receive a *negotiated distribution service* from *United Energy* (including on behalf of another).

(b) *Negotiated distribution services* provided by *United Energy* are more fully described in Schedule 1 to this Negotiating Framework, but generally are services related to the provision and relocation of public lighting assets.

(c) This Negotiating Framework has been prepared by *United Energy* to meet its obligations under Chapter 6 of the *Rules*. These *Rules* require that:

(i) *United Energy* prepare a document setting out the procedure to be followed during negotiations between it and a *Service Applicant* who wishes to receive a *negotiated distribution service*, as to the terms and conditions of access for the provision of the service (clause 6.7.5(a) of the *Rules*);

(ii) the negotiating framework comply with and be consistent with the applicable requirements of *United Energy's* distribution determination (clause 6.7.5(b) of the *Rules*); and

(iii) the negotiating framework comply with and be consistent with the applicable requirements of clause 6.7.5(c) of the *Rules*, which sets out the minimum requirements for a negotiating framework.

2 Application of Negotiating Framework

(a) This Negotiating Framework applies to *United Energy* and each *Service Applicant* who has made an application in writing to *United Energy* for the provision of a *negotiated distribution service* (including on behalf of another).

(b) *United Energy* and any *Service Applicant* who wishes to receive (including on behalf of another) a *negotiated distribution service* from *United Energy* must comply with the requirements of this Negotiating Framework.

(c) The requirements set out in this Negotiating Framework are additional to any requirements or obligations contained in the *Rules*. In the event of any inconsistency between this Negotiating Framework and any other requirements in the *Rules*, the requirements of the *Rules* will prevail.

(d) Nothing in this Negotiating Framework or in the *Rules* will be taken as imposing an obligation on *United Energy* to provide any service to the *Service Applicant*.

3 Commencement of negotiations

(a) A *Service Applicant* who wishes to receive (including on behalf of another) a *negotiated distribution service* from *United Energy* must first submit a written request to *United Energy* (***Offer Request***), which request must be in the form published by *United Energy* and contain the information, required by that form or any electricity industry code, guideline or standard, or any applicable law.

(b) In making a written request to *United Energy* the *Service Applicant* may request that *United Energy* first provide a preliminary non-binding budget estimate (rather than a formal offer, in accordance with clause 6), but must then separately provide a further written request to *United Energy* for a formal offer in accordance with clause 6 (which further request will be deemed to be the *Offer Request*).

4 Provision of Commercial Information by *Service Applicant*

4.1 Request for Commercial Information from Service Applicant

(a) Following receipt of a written request from a *Service Applicant*, *United Energy* may give notice to the *Service Applicant* requesting *Commercial Information* held by the *Service Applicant* that is reasonably required by *United Energy* to enable it to engage in effective negotiations with the *Service Applicant* in relation to the application and to enable *United Energy* to submit *Commercial Information* to the *Service Applicant*.

(b) The *Service Applicant* must use its reasonable endeavours to provide *United Energy* with the *Commercial Information* requested by *United Energy* in accordance with clause 4.1(a) within 10 *Business Day*s of that request, or within a time period as agreed by the parties.

4.2 Confidentiality Requirements for Service Applicant

(a) For the purposes of this clause 4, *Commercial Information* does not include:

(i) confidential information provided to the *Service Applicant* by another person; or

(ii) information that the *Service Applicant* is prohibited, by law, from disclosing to *United Energy*.

(b) *Commercial Information* may be provided by the *Service Applicant* subject to conditions including the condition that *United Energy* must not disclose the *Commercial Information* to any other person unless the *Service Applicant* consents in writing to the disclosure.

(c) The *Service Applicant* may require *United Energy* to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the *Service Applicant* in respect of any *Commercial Information* provided to *United Energy*.

(d) A consent provided by the *Service Applicant* in accordance with clause 4.2(b) may be subject to the condition that the person to whom *United Energy* discloses the *Commercial Information* must enter into a separate confidentiality agreement with the *Service Applicant*.

5 Provision of Commercial Information by *United Energy*

5.1 Request for Commercial Information from United Energy

(a) *United Energy* must provide *Commercial Information* to the *Service Applicant*, upon request, where such information is reasonably required by the *Service Applicant* to enable the *Service Applicant* to engage in effective negotiations with *United Energy* for the provision of a *negotiated distribution service*.

(b) For the purposes of clause 5.1(a), *Commercial Information* will include:

(i) the reasonable costs and/or the increase or decrease in costs (as appropriate) to provide the *negotiated distribution service* to the *Service Applicant*; and

(ii) a demonstration of how the price for providing the *negotiated distribution service* reflects those costs and/or the cost increment or decrement (as appropriate).

5.2 Confidentiality Requirements for United Energy

(a) For the purposes of this clause 5, *Commercial Information* does not include:

(i) confidential information provided to *United Energy* by another person; or

(ii) information that *United Energy* is prohibited, by law, from disclosing to the *Service Applicant*.

(b) *United Energy* may provide the *Commercial Information* in accordance with clause 5 subject to relevant conditions including the condition that the *Service Applicant* must not disclose the *Commercial Information* to any other person unless *United Energy* consents in writing to the disclosure.

(c) *United Energy* may require the *Service Applicant* to enter into a confidentiality agreement with *United Energy*, on terms reasonably acceptable to both parties, in respect of *Commercial Information* provided to the *Service Applicant*.

(d) A consent provided to a *Service Applicant* in accordance with clause 5.2(b) may be subject to the condition that a person to whom the *Service Applicant* discloses the *Commercial Information* must enter into a separate confidentiality agreement with *United Energy*.

6 Process and Timeframe for agreeing provision of negotiated distribution services

(a) Subject to clause 6(b), *United Energy* must make an offer to the *Service Applicant* to provide the *negotiated distribution service*, within 20 *Business Days* of receipt of an *Offer Request*, or within 20 *Business Days* of the date when *United Energy* receives all *Commercial Information* which *United Energy* reasonably requires for making the offer, whichever is later.

(b) *United Energy* may only refuse to make an offer to the *Service Applicant* to provide the *negotiated distribution service* if:

(i) *United Energy* has already made an offer in response to an earlier request and the offer has not been accepted: or

(ii) *United Energy* is permitted or required to do so by any electricity industry code, guideline or standard, or any applicable law.

(c) An offer made by *United Energy* must contain the price and terms and conditions for provision of the *negotiated distribution service*, including the following (as applicable):

(i) the amount of electricity *United Energy* fairly and reasonably estimates will be supplied to the *Service Applicant*, having regard to the *Service Applicant*'s load and connection characteristics;

(ii) the costs *United Energy* will incur to provide the relevant *negotiated distribution service*;

(iii) a requirement that the *Service Applicant* comply with the provisions of any electricity industry code, guideline or standard, unless otherwise agreed by the *United Energy* and the *Service Applicant* (both of whom in that respect must act reasonably).

(d) In preparing an offer to provide the *negotiated distribution service*, *United Energy* will comply with the requirements of Schedule 2, depending on the type of *negotiated distribution service* and the *Service Applicant*.

(e) An offer made by *United Energy* for provision of the *negotiated distribution service* will remain valid for a period of 60 days from the date of issue of the offer. Within that 60 day period the *Service Applicant* may notify *United Energy* that:

(i) it accepts *United Energy*'s offer;

(ii) it rejects *United Energy*'s offer and does not wish to commence with negotiations for provision of the *negotiated distribution service*; or

(iii) it rejects *United Energy*'s offer but does wish to commence with negotiations for provision of the *negotiated distribution service*.

(f) If the *Service Applicant* notifies *United Energy* that it rejects *United Energy*'s offer but does wish to commence with negotiations for provision of the *negotiated distribution service* then the framework for progressing and finalising negotiations set out in Table 1 will apply, where X refers to the date of the notice by the *Service Applicant* rejecting *United Energy's* offer.

Table 1

Event	Indicative Timeframe
Parties agree negotiation programme, which may include, without limitation, milestones relating to: - the request and provision of further *Commercial Information* by *United Energy* and the *Service Applicant*; - notification and consultation with any affected distribution network users	X + 15 *Business Days*
Parties finalise negotiations	X + 60 *Business Days*.

7 Obligation to negotiate in good faith

United Energy and the *Service Applicant* must negotiate in good faith the terms and conditions for the provision by *United Energy* of the *negotiated distribution service* sought by the *Service Applicant* and use reasonable endeavours to adhere to the timeframes referred to in clause 6.

8 Determination of impact on other distribution network users and consultation with affected distribution network users

(a) *United Energy* will determine the potential impact on distribution network users, other than the *Service Applicant*, of the provision of a *negotiated distribution service*.

(b) *United Energy* must notify and consult with any affected distribution network users to ensure that the provision of the *negotiated distribution service* does not result in non-compliance with obligations to other distribution network users under the *Rules*.

9 Suspension of Timeframe for Provision of a negotiated distribution service

(a) The timeframes in clause 6 for provision of an offer by *United Energy* or for negotiations for provision of a *negotiated distribution service*, are suspended if:

(i) a dispute in relation to the *negotiated distribution service* has been notified to the AER under Part 10 of the *NEL*, from the date of notification of that dispute to the AER until:

(A) the withdrawal of the dispute under section 126 of the *NEL*;

(B) the termination of the dispute by the AER under section 131 or 132 of the *NEL*; or

(C) determination of the dispute by the AER under section 128 of the *NEL*;

(ii) within 15 *Business Day*s of *United Energy* requesting additional *Commercial Information* from the *Service Applicant* pursuant to clause 4, the *Service Applicant* has not supplied that *Commercial Information*;

(iii) without limiting clauses 9(a)(i) or 9(a)(ii), the *Service Applicant* does not promptly conform with any of its obligations as required by this Negotiating Framework or as otherwise agreed between the parties;

(iv) *United Energy* has been required to notify and consult with any affected distribution network users under clause 8. Under these circumstances, the timeframes will be suspended from the date of notification to the affected distribution network users until the end of the time limit specified by *United Energy* for any affected distribution network users, or the receipt of such information from the affected distribution network users whichever is the later regarding the provision of the *negotiated distribution service*.

(b) Each party will notify the other party if it considers that the timeframe has been suspended, within 5 *Business Day*s of that suspension.

10 Dispute Resolution

(a) All disputes between the parties as to the terms and conditions for the provision of an *negotiated distribution service* are to be dealt with by *United Energy*'s dispute resolution processes in the first instance.

(b) Should *United Energy*' internal dispute resolution processes prove unsuccessful, disputes will be dealt with by the AER in accordance with Part 10 of the *NEL* and Chapter 8 of the *Rules*, as applicable.

11 Payment of *United Energy's* Reasonable Costs

(a) *United Energy* may give the *Service Applicant* a notice setting out the amounts payable in relation to *United Energy*' reasonable direct costs incurred in the processing of the *Service Applicant*'s application for a *negotiated distribution service*.

(b) The *Service Applicant* must, within 20 *Business Day*s of a notice being given in accordance with clause 11(a), pay to *United Energy* the amount set out in the notice.

12 Termination of Negotiations

(a) The *Service Applicant* may elect not to continue with its application for the provision of a *negotiated distribution service* and may terminate the negotiations by giving *United Energy* written notice of its decision to do so. Under such circumstances, the *Service Applicant* will still be liable for *United Energy's* incurred and/or committed costs in relation to the provision of that service.

(b) *United Energy* may terminate a negotiation under this framework by giving the *Service Applicant* written notice of its decision to do so where:

(i) *United Energy* believes on reasonable grounds that the *Service Applicant* is not conducting the negotiation under this Negotiating Framework in good faith;

(ii) the *Service Applicant* consistently fails to comply with the requirements of the Negotiating Framework;

(iii) the *Service Applicant* fails to comply with an obligation in this Negotiating Framework to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action within 20 *Business Day*s of a written request from *United Energy*;

(iv) the *Service Applicant* fails to make required payments in relation to the provision of the service; or

(v) an act of *Solvency Default* occurs in relation to the *Service Applicant*.

13 Publication of Results of negotiations on website

United Energy will publish on its website a quarterly summary of the *negotiated distribution services* provided to categories of *Service Applicant*s and the total value of those services.

14 Giving notices

(a) A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

(b) If a party gives the other party 3 *Business Day*s notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered, posted or electronically transmitted to the latest address.

United Energy

c/o Jemena Limited
321 Ferntree Gully Road
Mt Waverley, Vic, 3149
Postal Address:
Locked Bag 7000
Mount Waverley Vic 3149
Telephone 13000 131 689
Fascimile 1300 131 684.

Service Applicant

Name: *Service Applicant*

Address: The nominated address of the *Service Applicant* provided in writing to *United Energy* as part of the application.

(c) A notice, consent, information, application or request is to be treated as given or made at the following time:

(i) if it is handed to a party, on the day that this occurs;

(ii) if it is delivered, when it is left at the relevant address;

(iii) if it is sent by post, 2 *Business Day*s after it is posted:

(iv) if sent by facsimile transmission, on the day the transmission is sent, but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission; or

(v) if sent by e-mail, on the day the e-mail is sent, provided that a confirmation that the e-mail was received by the recipient is received by the sender.

(d) If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next *Business Day*.

15 Miscellaneous

15.1 Governing law and jurisdiction

(a) This document is governed by the law of the State of Victoria.

(b) The parties submit to the non-exclusive jurisdiction of the courts of the State of Victoria

(c) The parties will not object to the exercise of judgment by the courts of the State of Victoria on any basis.

15.2 Severability

(a) If a clause or part of a clause of this Negotiating Framework can be read in a way that makes it illegal, unenforceable or invalid, but can also be read in a way that makes is legal, enforceable and valid, it must be read in the latter way.

(b) If any clause or part of a clause is illegal, unenforceable or invalid, that clause or part is to be treated as removed from this Negotiating Framework, but the rest of this Negotiating Framework is not affected.

15.3 Time for Action

If the day on or by which something is required to be done is not a *Business Day*, that thing must be done on or by the next *Business Day*.

16 Definitions and interpretation

16.1 Definitions

In this document the following definitions apply:

Act means the *Electricity Industry Act 2000*.

Business Day means a day other than a Saturday or Sunday or a public holiday appointed under the *Public Holidays Act 1993*.

Commercial Information will include at a minimum, the following classes of information in relation to a *Service Applicant*, where applicable:

(a) Details of corporate structure, financial details relevant to creditworthiness and commercial risk and ownership of assets;

(b) Technical information relevant to the application for a *negotiated distribution service*;

(c) Financial information relevant to the application for a *negotiated distribution service*;

(d) Details of an application's compliance with any law, standard, *Rules* or guideline.

distribution fixed assets means any distribution fixed assets used by *United Energy* to distribute or supply electricity, whether or not located in *United Energy's* distribution area.

***negotiated distribution service*(s)** means those services specified as *negotiated distribution services* in Schedule 1.

NEL means the National Electricity Law.

Offer Request has the meaning given in clause 3(a).

Rules means the rules call the National Electricity Rules made under Part 7 of the *NEL* as amended from time to time in accordance with that Part 7.

Service Applicant means either:

(a) a person who is an existing or an intending Registered Participant or a person who is eligible to become a Registered Participant; or

(b) a person who asks *United Energy* for access to a distribution service.

Solvency Default means the occurrence of any of the following events in relation to the *Service Applicant*:

(a) An originating process or application for the winding up of the *Service Applicant* (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the *Service Applicant*, and is not dismissed before the expiration of 60 days from service on the *Service Applicant*;

(b) A receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the *Service Applicant*, or a provisional liquidator is appointed to the *Service Applicant*;

(c) A mortgagee, chargee or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the *Service Applicant*;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The *Service Applicant* stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The *Service Applicant* applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the *Service Applicant* or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the *Service Applicant*'s property;

(h) The *Service Applicant* takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the *Service Applicant*;

(i) A controller (as defined in the Corporations Act 2001) is appointed in respect of any part of the property of the *Service Applicant*;

(j) Except to reconstruct or amalgamate while solvent, the *Service Applicant* enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the *Service Applicant*'s affairs;

(k) The *Service Applicant* is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001; or

(l) Anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the *Service Applicant*.

United Energy means United Energy Distribution Pty Ltd (ABN 70 064 651 029).

16.2 Interpretation

In this document, unless the context otherwise requires:

(a) terms defined in the *NEL* and the *Rules* have the same meaning in this Negotiating Framework;

(b) a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

(c) a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

(d) a reference to a clause, part, schedule or attachment is a reference to a clause, part, schedule or attachment of or to this document unless otherwise stated;

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

(f) a covenant or agreement on the part of two or more persons binds them jointly and severally.

1 Schedule 1 –Negotiated Distribution Services

The negotiated distribution services provide by *United Energy* are:

(a) *public lighting services*, being alternation and relocation of *United Energy* public lighting assets and the provision of new public lighting assets.

2 Schedule 2 - Pricing Principles

Public Lighting Services

1 In making an offer for a *negotiated distribution service* that is a *public lighting service United Energy* must include a price that is fair and reasonable having regard to the costs to be incurred by *United Energy* in providing that service and which is otherwise consistent with its obligations under the *Rules*.

Assessment and Review

2 *United Energy* will annually assess and review prices for *negotiated distribution services* and the basis upon which those prices are made.

3 *United Energy* must make information on the assessment and review available in accordance with clause 5 of the Negotiating Framework.

D Negotiated distribution service criteria

D.1 National Electricity Objective

1. The terms and conditions of access for a negotiated distribution service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective.

D.1.1 Criteria for terms and conditions of access

D.1.1.1 Terms and conditions of access

1. The terms and conditions of access for a negotiated distribution service must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
2. The terms and conditions of access for a negotiated distribution service (including in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between a distribution network service provider (DNSP) and any other party, the price for the negotiated distribution service and the costs to a DNSP of providing the negotiated distribution service.
3. The terms and conditions of access for a negotiated distribution service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

D.1.1.2 Price of services

1. The price for a negotiated distribution service must reflect the costs that a DNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the DNSP's Cost Allocation Method.
2. Subject to criteria 7 and 8, the price for a negotiated distribution service must be at least equal to the cost that would be avoided by not providing that service but no more than the cost of providing it on a stand alone basis.
3. If a negotiated distribution service is a shared distribution service that:
    i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation: or
    ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER,
4. then the difference between the price for that service and the price for the shared distribution service which meets network performance requirements must reflect a DNSP's incremental cost of providing that service (as appropriate).
5. If a negotiated distribution service is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared distribution service which meets, but does not exceed, the network performance

requirements, should reflect the cost a DNSP would avoid by not providing that service (as appropriate).

6. The price for a negotiated distribution service must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiated distribution service to different Distribution Network Users or classes of Distribution Network Users.
7. The price for a negotiated distribution service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.
8. The price for a negotiated distribution service must be such as to enable a DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated service.

D.1.2 Criteria for access charges

D.1.2.1 Access charges

1. Any charges must be based on costs reasonably incurred by a DNSP in providing distribution network user access, and, in the case of compensation referred to in clauses 5.5(f)(4)(ii) and (iii) of the NER, on the revenue that is likely to be forgone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).
2. Any charges must be based on costs reasonably incurred by a DNSP in providing transmission network user access to services deemed to be negotiated distribution services by clause 6.24.2(c) of the NER, and, in the case of compensation referred to in clauses 5.4A(h) to (j) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

E Distribution tariffs

E.1 Changes to tariff structures

This appendix sets out the approach to estimating the historical quantity weights and the substitute values for the current tariffs/tariff components to be used when calculating compliance with the WAPC and the side constraint formulas.

Changes to tariff structures can occur for customers in the following circumstances:

- the introduction of new tariffs or tariff components (for example, introducing a step rate for the usage component of a tariff)
- adjustments to existing tariffs or tariff components (for example, changing the threshold on an inclining block tariff or the time bands associated with time of use tariffs). This is essentially the same as introducing new tariffs or tariff components
- when customers move between existing tariffs (from origin tariffs to alternative tariffs) due for instance to a change in metering arrangements.

For those tariffs subject to a change in structure, the values of the parameters in the weighted average price cap (WAPC) and side constraints formulas applying to the control mechanism will require adjustments. Specifically, adjustments will be required to:

- the historical quantity weights (q_{t-2}^{ij}) for these tariffs
- the values of the current tariffs/tariff components in the WAPC and side constraints formulas (p_{t-1}^{ij}).

For simplicity of presentation, any discussion in this appendix in relation to p_{t-1}^{ij} and q_{t-2}^{ij} should be taken to be equally applicable to the WAPC and the side constraints, unless otherwise specified.

E.1.1 Introducing new tariffs or tariff components

E.1.1.1 The value of q_{t-2}^{ij}

Both the WAPC and side constraints are calculated using audited historical quantities of consumption. However, historical quantities for any new tariffs/tariff components will not be available until two years after the tariffs/tariff components have been introduced.

In order to incorporate new tariff structures in the WAPC and the side constraints, the AER requires reasonable estimates to be submitted by the DNSP, based on the quantities that would have been sold if the new tariff/tariff components had been introduced in year ‘*t–2*’. The approach to deriving reasonable estimates is as follows.

First, the DNSP must nominate the origin tariffs/tariff components, which represent the tariffs/tariff components that the customers, who will be moved to the new network tariffs/tariff components, are currently being charged.

Second, the DNSP must provide reasonable estimates of q_{t-2}^{ij} for all applicable units of measure (for example kWh, kW) for both the new tariffs/tariff components, and the origin tariffs/tariff components. The DNSP must make the following assumptions when calculating these reasonable estimates:

1. The only customers who would have moved to the new network tariff/tariff component in year t–2 did so due to a change in tariff structures initiated by the DNSP and as permitted under the customers' network connection contract. This means that no new customers are included in the estimate,[1] and nor are customers who request to change tariff either voluntarily, or through the actions of a retailer.
2. Customers have the same consumption and load profile on the new tariff/tariff component as they did on the origin tariff/tariff component. This implies that the sum of the reasonable estimates for year t–2 for each unit of measure on the new tariff/tariff component plus the reasonable estimates for year t–2 for each unit of measure on the origin tariff/tariff component, equals the actual audited quantities that occurred for the origin tariff/tariff component in year t–2.
   a. Where a new tariff is created specifically for a new customer, the DNSP is to provide reasonable estimates for year t–2 for each unit of measure on the new tariff/tariff component. The DNSP is to provide the reasoning and information for the reasonable estimates including but not limited to the factors set out in section E.1.4 as relevant.

In the year after a new tariff/tariff component has been introduced, there will still be no full year of audited historical data available to be used for q_{t-2}^{ij}. As a result the DNSP will be required to again submit reasonable estimates for both the new tariff/tariff component and the corresponding origin tariff/tariff component. At this time, however, the DNSP may base the reasonable estimates on the actual quantities that have occurred to date on the new tariff/tariff components and origin tariff/tariff components. The DNSP must demonstrate how it has arrived at the estimates.

E.1.1.2 The value of p_{t-1}^{ij}

The p_{t-1}^{ij} of the corresponding origin tariff/tariff components will be used as the p_{t-1}^{ij} for the new tariff/tariff components, where both the origin and new tariff components are measured in the same units of measure.

Where the origin and new tariff components are measured in different units of measure, a DNSP can derive the value of p_{t-1}^{ij} using an appropriate conversion factor. The DNSP must provide the details and reasoning for the use of the conversion factor.

If there is no corresponding origin tariff/tariff components with the same units of measure, and there is no appropriate conversion factor, p_{t-1}^{ij} will be set to zero.

[1] New customers have been allowed for in the growth assumption used when setting the X factor in the post tax revenue model.

Where a new tariff is created specifically for a new customer, the DNSP is to assume that $p_t^{ij} = p_{t-1}^{ij}$. The DNSP is to provide the reasoning and information for p_t^{ij} and p_{t-1}^{ij} including but not limited to the factors set out in section E.1.4 as relevant and clause 6.18 of the NER.

Example: Changing units of measure

A DNSP proposes changing some tariff components from KWh to KVA. To do this:

1. The DNSP must demonstrate how KWh converts to KVA (e.g. the power factor(s) used and why this was chosen). For the example, assume 1 KWh = 1.1 KVA.
2. The origin quantities and prices are converted as shown in the table E.1 below. The aim in recalculating the tariff component charge (p_{t-1}^{ij}) is to confirm the same notional revenues under both the KWh and KVA approaches.

Table E.1 Changing units of measure

	Origin component	Revised component
p_{t-1}^{ij}	5.0000 c/KWh	4.5455 c/KVA
q_{t-2}^{ij}	10 000 KWh	11 000 KVA
Notional revenue	$500	$500

E.1.1.3 Example 1: Introducing an inclining block tariff component

This example assumes that a domestic tariff with a single variable rate is amended so that there are now two variable rates based on a customer's level of consumption. For each of the 25 000 customers on this tariff, their historical consumption is split between consumption up to 5000kWh per annum and any residual consumption above this amount. Under this approach, the total consumption for this tariff class of 200 000MWh is split, 150 000MWh against variable rate 1 and 50 000MWh against variable rate 2 as shown in the example set out in table E.2.

Table E.2 Determining p_{t-1}^{ij} and q_{t-2}^{ij} in example 1

		p_{t-1}^{ij}	q_{t-2}^{ij}
Origin tariff —standard domestic			
Fixed charge	$ pa per customer	30	25 000 customers
Variable rate (all consumption)	c/kWh	0.04	200 000 MWh
Proposed tariff with new component			
Fixed charge	$ pa per customer	30	25 000 customers
Variable rate 1 (consumption ≤ 5000kWh pa per customer)	c/kWh	0.04 (as per origin tariff)	150 000 MWh
Variable rate 2 (consumption > 5000kWh pa per customer)	c/kWh	0.04 (as per origin tariff)	(200 000 –150 000) = 50 000 MWh

Note: While the variable rates (1 & 2) that the DNSP proposes for the next year (p_t^{ij}) are likely to differ, the divergence in these rates is constrained by the overall WAPC and the side constraints for this tariff class.

E.1.2 Customers transferred to an alternative tariff

E.1.2.1 The value of q_{t-2}^{ij}

The DNSP may decide to transfer customers if a customer's consumption or load profile has changed and the DNSP decides it is no longer appropriate for them to remain on the same tariff. Alternatively the DNSP may change the structure of an existing tariff to suit the majority of customers. Appendix G sets out the procedures a DNSP must adhere to in assigning or reassigning customers to tariff classes.

If the DNSP proposes to move a number of customers to an alternative existing tariff, the rate at which revenue will accrue from these customers will be different to that used to calculate the X factor in the post tax revenue model and will be different to what will be calculated under the WAPC formula. In addition, the side constraint formula will not fully reflect the actual tariff change for the customers being transferred when the customers are transferred to a different tariff class, as the overall tariff change observed by these customers will consist of not only the side constraint on the alternative tariff class but the difference between the origin tariff the customer was on and the alternative tariff to which they are being transferred. If the DNSP proposes to move a number of customers to an alternative existing tariff (whether the transfer occurs within the same tariff class or to a different tariff class), the AER will require the DNSP to submit reasonable estimates for q_{t-2}^{ij} for each origin tariff that the customer is currently on, and the new tariff that the DNSP will move the customers to, taking the transfer into account.

For compliance purposes, the assumptions the DNSP must make when calculating the reasonable estimates are:

1. the customer movement occurred in year t–2
2. the customers only moved as a result of a change in tariff structures initiated by the DNSP and as permitted the customers' network connection contract. The estimates are not to include customers who choose to move at their discretion or movements caused by a retailer's action
3. customers have the same consumption and load profile under either tariff.

Reasonable estimates will also be required in the year following the movement as there will be no full year of audited historical data available in that year.

E.1.2.2 The value of p_{t-1}^{ij}

The p_{t-1}^{ij} for the corresponding origin tariff/tariff components will be used as the p_{t-1}^{ij} for the new tariff components.

When calculating the side constraint, the p_{t-1}^{ij} is to equal the tariff in year *t–1* of the tariff class the customer is being reassigned where the customer has been reassigned to a different tariff class.

E.1.2.3 Example 2: Re-assigning some customers from the domestic flat rate tariff to the domestic TOU tariff

This example assumes 10 000 customers with consumption of 70 000 MWh will be moved by the DNSP from the domestic tariff to a domestic TOU tariff, which already has 5000 customer. Both tariffs remain in existence and there will be customers on both tariffs. The allocation of the 70 000 MWh across the peak, shoulder and off–peak reflects historical consumption patterns of these customers. The calculations of the WAPC and side constraint are shown in tables E.3 and E.4 respectively. Table E.4 demonstrates that when a customer is reassigned to an existing tariff in a different tariff class, p_{t-1}^{ij} is to equal the tariff in year *t–1* of the tariff class the customer is being reassigned as required under section E.1.2.2.

Table E.3 Determining p_{t-1}^{ij} and q_{t-2}^{ij} in example 2

		p_{t-1}^{ij}	q_{t-2}^{ij}
Domestic tariff			
Fixed charge	$ pa per customer	30	(25 000 existing – 10 000) = 15 000 customers
Variable rate (any time)	c/kWh	0.04	(200 000 existing – 70 000) = 130 000 MWh
Domestic TOU tariff—existing customers			
Fixed charge	$ pa per customer	22	5 000 existing
Peak rate	c/kWh	0.09	10 000 MWh existing
Shoulder rate	c/kWh	0.05	10 000 MWh existing
Off–peak rate	c/kWh	0.02	10 000 MWh existing
Domestic TOU tariff—customers being transferred			
Fixed charge	$ pa per customer	30 (as per domestic)	10 000 customers
Peak rate	c/kWh	0.04 (as per domestic)	25 000 MWh
Shoulder rate	c/kWh	0.04 (as per domestic)	20 000 MWh
Off–peak rate	c/kWh	0.04 (as per domestic)	25 000 MWh

Note: The Domestic TOU tariff the DNSP proposes for next year (p_t^{ij}) will apply equally across all (15 000) customers now on that tariff, which must be within the constraints of the WAPC and side constraints.

Table E.4 Determining p_{t-1}^{ij} and q_{t-2}^{ij} for the side constraint in example 2 where a tariff class reassignment occurs (the domestic and domestic TOU tariffs belong to different tariff classes)

		p_{t-1}^{ij}	q_{t-2}^{ij}
Domestic tariff			
Fixed charge	$ pa per customer	30	(25 000 existing – 10 000) = 15 000 customers
Variable rate (any time)	c/kWh	0.04	(200 000 existing – 70 000) = 130 000 MWh
Domestic TOU tariff—existing customers			
Fixed charge	$ pa per customer	22	5 000 existing
Peak rate	c/kWh	0.09	10 000 MWh existing
Shoulder rate	c/kWh	0.05	10 000 MWh existing
Off–peak rate	c/kWh	0.02	10 000 MWh existing
Domestic TOU tariff– customers being transferred			
Fixed charge	$ pa per customer	22 (as per domestic TOU)	10 000 customers
Peak rate	c/kWh	0.09 (as per domestic TOU)	25 000 MWh
Shoulder rate	c/kWh	0.05 (as per domestic TOU)	20 000 MWh
Off–peak rate	c/kWh	0.02 (as per domestic TOU)	25 000 MWh

Note: The Domestic TOU tariff the DNSP proposes for next year (p_t^{ij}) will apply equally across all (15 000) customers now on that tariff, which must be within the constraints of the WAPC and side constraints.

E.1.3 Note on switching rates

Where the switching rates of distribution customers moving from a given parent distribution tariff(s) to a proposed new distribution tariff will continue to be above zero from calendar year to calendar year, application of the WAPC formula in chapter 4 of this final decision will distinguish between:

a. distribution customers who have already moved to the new tariff. In this case q_{t-2}^{ij} will be based on actual quantities sold in relevant units to distribution customers who have already switched to the new distribution tariff, and p_t^{ij} is the new distribution tariff; and

b. distribution customers who are expected to switch to the new distribution tariff during calendar year *t*. In this case q_{t-2}^{ij} will be based on the estimates of the quantities which would have been sold in calendar year *t–2*, in accordance with sections E.1.1 and E.1.2 as appropriate, and p_t^{ij} is the new tariff.

E.1.4 AER assessment of reasonable estimates

When assessing the reasonableness of quantity estimates provided by the Victorian DNSPs, the AER will take the following information into account:

1. the actual audited quantities sold in relevant units under the origin tariff in previous years
2. a forecast of the number of distribution customers that the DNSP states will move to the new tariff/tariff components, and the reasons for the move
3. a forecast of the number of distribution customers that the DNSP expects will remain on the origin tariff
4. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that are to be moved to the new tariff/tariff components
5. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that will remain on the origin tariff
6. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will be moved to the new tariff/tariff components
7. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will remain on the origin tariff
8. the approach the DNSP used to determine its forecasts (for 2–7 above)
9. the materiality of the reasonable estimates
10. further information as required by the AER.

E.2 Calculation of the licence fee factor

E.2.1

The licence fee pass through adjustment (L_t) to the distribution price control in the calendar year t, for a given DNSP is expressed by the formula set out in subclause E.2.2 below.

E.2.2

The licence fee pass through adjustment L_t that will apply in calendar year *t* after the calendar year ending 31 December 2010, for each DNSP, is:

$$L_t = \left(\frac{1 + L'_t}{1 + L'_{t-1}} \right) - 1$$

where

$$L'_t = \frac{lf_{t-1}\left(1 + pretaxWACC_D\right)^{3/2}\left(1 + CPI_t\right)^{3/2}}{\left(1 + CPI_t\right)\left(1 - X_t\right)\left(1 + S_t\right)\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-1}^{ij}}$$

L'_{t-1} (a) if regulatory year *t* is prior to calendar year ending 31 December 2012, is zero;

(b) if regulatory year *t* is after calendar year ending 31 December 2011, is the value of $L_t^{'}$ determined in the calendar year *t–1*;

lf_{t-1} is the licence fee paid by the DNSP for the financial year ending in June of the regulatory year *t–1*;

CPI_t is defined as set out in chapter 4 of this final decision

X_t is the value of X for year *t* of the regulatory control period as determined by the AER in chapter 18 of this final decision.

S_t (a) if regulatory year *t* is prior to calendar year ending 31 December 2013, is zero

(b) if regulatory year *t* is after calendar year ending 31 December 2012, is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*;

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

q_{t-1}^{ij} is the estimated quantity of distribution tariff component *j* of distribution tariff *i* in regulatory year *t–1*; and

$pretaxWACC_D$ is the real pre-tax WACC applying to each Victorian DNSP and are as follows in table E.5.

Table E.5 Real pre tax WACC (per cent)

JEN	7.92
CitiPower	7.37
Powercor	7.30
SP AusNet	7.41
United Energy Distribution	7.39

E.3 Calculation of the pass through factor

The AER applies the Maximum Pass through revenue (MPR_t) formula in this appendix as part of its consideration on whether or not to verify as compliant the DNSP's proposed distribution tariffs.

E.3.1

1. The $passthrough_t$ adjustment to the distribution price control in the calendar year t, for a given DNSP is derived as set out in subclause E.3.2 below.

E.3.2 Implementation mechanism

Maximum Pass through Revenue (MPR_t)

1. MPR_t is expressed by the formula as set out below:

$$MPR_t = PC_t - K_t$$

where:

MPR_t (in ¢) is the maximum revenue the DNSP is allowed to receive from its pass through tariffs from all distribution customers for the calendar year *t*;

PC_t (in ¢) is the aggregate amount of all positive and negative change events approved for pass through by the AER, during calendar year t; and

K_t (in ¢) is determined in accordance with clause E.3.3 of this appendix.

2. The $passthrough_t$ factor in the WAPC and side constraint set out respectively in chapter 4 sections 4.5.1 and 4.5.2 of this final decision represent the incremental charges (incremental pass through charges) derived from MPR_t and the forecast quantities for year *t*.

E.3.3 Implementation mechanism

Correction factor K_t

1. K_t is a correction factor to account for any under or over recovery of actual revenue from incremental pass through charges in relation to the aggregate amount of all positive and negative change events approved for pass through by the AER.
2. K_t is determined by reference to the formula set out below.

$$K_t = (Ky_t + Kz_t + K_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

where:

Ky_t (in ¢) is calculated in accordance with clause E.3.4;

Kz_t (in ¢) is calculated in accordance with clause E.3.5;

K_{t-1} (in ¢) is the figure calculated for K_t for calendar year *t–1*;

pretax $WACC_D$ is as set out in appendix E.2 of this final decision; and

CPI_t is defined as set out in chapter 4 of this final decision

E.3.4 Implementation mechanism

Calculation of Ky_t

1. Ky_t is a correction factor determined with reference to the formula in this clause.

$$Ky_t = PR_{t-1} - PC_{t-1}$$

where:

PR_{t-1} (in ¢) is the total revenue which it is estimated the DNSP will earn from the incremental pass through charges in respect of all distribution customers in calendar year *t-1*; and

PC_{t-1} (in ¢) is the aggregate amount of all positive and negative change events approved for pass through by the AER, during calendar year *t-1*.

E.3.5 Implementation mechanism

Calculation of Kz_t

1. Kz_t is a correction factor for the difference between the estimates made in clause E.3.4 of this appendix in calendar year *t-1* and actual audited values and is expressed by the formula in this clause.

$$Kz = \{(\Pr a_{t-2} - P\,\mathrm{Re}_{t-2}) - (PCa_{t-2} - PCe_{t-2})\} \times (1 + pretaxWACC_D) \times (1 + CPI_{t-1})$$

where:

PRa_{t-2} (in ¢) is the actual audited total revenue earned by the DNSP from the incremental pass through charges in respect of all distribution customers in calendar year *t–2*;

$P\,\mathrm{Re}_{t-2}$ (in ¢) is the figure used for PR_{t-1} when calculating Ky_t for calendar year *t-2* under clause E.3.4;

PCa_{t-2} (in ¢) is the audited aggregate amount of all positive and negative change events approved for pass through by the AER, during calendar year *t-2*;

PCe_{t-2} (in ¢) is the figure used for PC_{t-1} when calculating Ky_t for calendar year *t*-1 under clause E.3.4;

CPI_{t-1} is the CPI_t as set out in chapter 4 of this final decision for the calendar year *t-1*.

pretax $WACC_D$ is as set out in appendix E.2 of this final decision.

F Transmission tariffs and jurisdictional schemes

F.1 Introduction

To demonstrate compliance with clauses 6.18.7 and 6.18.7A of the National Electricity Rules (NER) and this final decision in the 2011-15 regulatory control period, the AER requires the Victorian DNSPs to maintain an unders and overs account for the charges described in clauses 6.18.7 (6.18.7 charges) and 6.18.7A (6.18.7A charges) of the NER. The Victorian DNSPs must provide information on this account to the AER as part of its annual pricing proposals under clause 6.18.2(b)(7) of the NER.

As part of its pricing proposal for each regulatory year of the 2011-15 regulatory control period, the Victorian DNSPs must provide details of their calculations of the 6.18.7 charges and 6.18.7A charges that they incurred including the unders and overs components as set out in this appendix.

The Victorian DNSPs must provide details of calculations of 6.18.7 charges and 6.18.7A charges in the format set out in appendices F.2 and F.3 respectively of this final decision below. Amounts provided for the most recently completed regulatory year must be audited. Amounts for the current and next regulatory year will be regarded as estimates and forecasts respectively.

In proposing variations to the amount and structure of the 6.18.7 charges and 6.18.7A charges, the Victorian DNSPs are to achieve a zero expected balance on its unders and overs accounts at the end of each regulatory year in the 2011–15 regulatory control period.

F.2 Maximum transmission revenue control formula

The AER applies the Maximum Transmission Revenue control formula in this appendix when considering whether or not to verify as compliant the DNSP's proposed tariffs for the charges described in clause 6.18.7 of the NER (6.18.7 tariffs).

F.2.1

When assessing a DNSP's proposed 6.18.7 tariffs, submitted in accordance with clause 6.18.2 of the NER, the AER will assess whether the expected revenue from 6.18.7 tariffs (TR_t), is less than or equal to the Maximum Transmission Revenue (MTR_t):

$$TR_t \leq MTR_t$$

where

MTR_t is determined by the formula in clause F.2.2 of this appendix; and

TR_t is the total of the DNSP's proposed 6.18.7 tariffs multiplied by the corresponding forecast quantities to be distributed for each 6.18.7 tariff component of each 6.18.7 tariff, in calendar year *t*.

F.2.2 Maximum Transmission Revenue (*MTR*t)

1. MTR_t is expressed by the formula as set out below:

$$MTR_t = TC_t - K_t$$

where:

MTR_t (in ¢) is the maximum revenue the DNSP is allowed to receive from its 6.18.7 tariffs from all distribution customers for the calendar year *t*;

TC_t (in ¢) is the aggregate of all 6.18.7 charges which the DNSP forecasts it will be required to pay during calendar year *t*; and

K_t (in ¢) is a correction factor determined in accordance with clause F.2.3 of this appendix.

F.2.3 Correction factor *K*t

1. K_t is a correction factor to account for any under or over recovery of actual revenue from 6.18.7 tariffs in relation to allowed revenue from 6.18.7 tariffs.
2. K_t is determined by reference to the formula set out below.

$$K_t = (Ky_t + Kz_t + K_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

where:

Ky_t (in ¢) is calculated in accordance with clause F.2.4;

Kz_t (in ¢) is calculated in accordance with clause F.2.5;

K_{t-1} (in ¢) is the figure calculated for K_t for calendar year *t–1;*

pretax $WACC_D$ is as set out in appendix E of this final decision; and

CPI_t is defined in chapter 4 of this final decision.

F.2.4 Calculation of Ky_t

1. Ky_t is a correction factor determined with reference to the formula in this clause.

$$Ky_t = TR_{t-1} - TC_{t-1}$$

where:

TR_{t-1} (in ¢) is the total revenue which it is estimated the DNSP will earn from its 6.18.7 tariffs in respect of all distribution customers in calendar year *t-1*; and

TC_{t-1} (in ¢) is the aggregate of all 6.18.7 charges which it is estimated will be payable by the DNSP during calendar year *t-1*.

F.2.5 Calculation of Kz_t

1. Kz_t is a correction factor for the difference between the estimates made in clause F.2.4 of this appendix in calendar year *t-1* and actual audited values and is expressed by the formula in this clause.

$$Kz_t = \{(TRa_{t-2} - T\text{Re}_{t-2}) - (TCa_{t-2} - TCe_{t-2})\} \times (1 + pretaxWACC_D) \times (1 + CPI_{t-1})$$

where:

TRa_{t-2} (in ¢) is the actual audited total revenue earned by the DNSP from 6.18.7 tariffs in respect of all distribution customers in calendar year *t–2*;

$T\text{Re}_{t-2}$ (in ¢) is the figure used for TR_{t-1} when calculating Ky_t for calendar year *t-2* under clause F.2.4;

TCa_{t-2} (in ¢) is the audited aggregate of all 6.18.7 charges which were paid by the DNSP during calendar year *t-2*;

TCe_{t-2} (in ¢) is the figure used for TC_{t-1} when calculating Ky_t for calendar year *t*-1 under clause F.2.4;

CPI_{t-1} is CPI_t as set out in chapter 4 of this final decision for the calendar year *t-1*.

pretax $WACC_D$ is as set out in appendix E of this final decision.

F.3 Maximum jurisdictional schemes revenue control formula

The AER applies the Maximum Jurisdictional Schemes Revenue control formula in this appendix when considering whether or not to verify as compliant the DNSP's proposed tariffs for the charges described in clause 6.18.7A of the NER (6.18.7A tariffs).

F.3.1

When assessing a DNSP's proposed 6.18.7A tariffs, submitted in accordance with clause 6.18.2 of the NER, the AER will assess whether the expected revenue from 6.18.7A tariffs (JR_t), is less than or equal to the Maximum Jurisdictional Schemes Revenue (MJR_t):

$$JR_t \leq MJR_t$$

where

MJR_t is determined by the formula in clause F.3.2 of this appendix; and

JR_t is the total of the DNSP's proposed 6.18.7A tariffs multiplied by the corresponding forecast quantities to be distributed for each 6.18.7A tariff component of each 6.18.7A tariff, in calendar year *t*.

F.3.2 Maximum Jurisdictional Scheme Revenue (MJR_t)

1. MJR_t is expressed by the formula as set out below:

$$MJR_t = PC_t - K_t$$

where:

MJR_t (in ¢) is the maximum revenue the DNSP is allowed to receive from its 6.18.7A tariffs from all distribution customers for the calendar year *t*;

PC_t (in ¢) is the aggregate of all 6.18.7A charges which the DNSP forecasts it will be required to pay during calendar year *t*, and

K_t (in ¢) is determined in accordance with clauses F.3.3.

F.3.3 Correction factor K_t

1. K_t is a correction factor to account for any under or over recovery of actual revenue from 6.18.7A tariffs in relation to allowed revenue from 6.18.7A tariffs.
2. K_t is determined by reference to the formula set out below.

$$K_t = (Ky_t + Kz_t + K_{t-1}) \times (1 + CPI_t) \times (1 + pretaxWACC_D)$$

where:

Ky_t (in ¢) is calculated in accordance with clause F.3.4;

Kz_t (in ¢) is calculated in accordance with clause F.3.5;

K_{t-1} (in ¢) is the figure calculated for K_t for calendar year *t–1*;

pretax $WACC_D$ is as set out in appendix E of this final decision; and

CPI_t is defined as set out in chapter 4 of this final decision.

F.3.4 Calculation of Ky_t

1. Ky_t is a correction factor determined with reference to the formula in this clause.

$$Ky_t = JR_{t-1} - PC_{t-1}$$

where:

JR_{t-1} (in ¢) is the total revenue which it is estimated the DNSP will earn from its 6.18.7A tariffs in respect of all distribution customers in calendar year *t-1*; and

PC_{t-1} (in ¢) is the aggregate of all 6.18.7Acharges which it is estimated will be payable by the DNSP, during calendar year *t-1*.

F.3.5 Calculation of Kz_t

1. Kz_t is a correction factor for the difference between the estimates made in clause F.3.4 of this appendix in calendar year *t-1* and actual audited values and is expressed by the formula in this clause.

$$Kz_t = \{(JRa_{t-2} - J\mathrm{Re}_{t-2}) - (PCa_{t-2} - PCe_{t-2})\} \times (1 + pretaxWACC_D) \times (1 + CPI_{t-1})$$

where:

JRa_{t-2} (in ¢) is the actual audited total revenue earned by the DNSP from 6.18.7A tariffs in respect of all distribution customers in calendar year *t–2*;

$J\mathrm{Re}_{t-2}$ (in ¢) is the figure used for JR_{t-1} when calculating Ky_t for calendar year *t-2* under clause F.3.4;

PCa_{t-2} (in ¢) is the audited aggregate of all 6.18.7A charges which were paid by the DNSP during calendar year *t-2*;

PCe_{t-2} (in ¢) is the figure used for PC_{t-1} when calculating Ky_t for calendar year *t*-1 under clause F.3.4;

CPI_{t-1} is CPI_t as set out in chapter 4 of this final decision for the calendar year *t-1*.

pretax $WACC_D$ is as set out in appendix E of this final decision.

G Assigning customers to tariff classes

Procedures for assigning or reassigning customers to tariff classes

The procedures outlined in this appendix apply to direct control services.

Assignment of existing customers to tariff classes at the commencement of the 2011-15 regulatory control period

1. Each customer who was a customer of a Victorian DNSP prior to 1 January 2011, and who continues to be a customer of a Victorian DNSP as at 1 January 2011, will be taken to be “assigned” to the tariff class under which the Victorian DNSP was charging that customer immediately prior to 1 January 2011.

Assignment of new customers to a tariff class during the 2011-15 regulatory control period

2. If, after 1 January 2011, a Victorian DNSP becomes aware that a person will become a customer of the DNSP, then the DNSP must determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with paragraphs 2 or 5 of this appendix, a DNSP must take into account one or more of the following factors:
   a. the nature and extent of the customer’s usage
   b. the nature of the customer’s connection to the network
   c. whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under paragraph 3 of this appendix, a Victorian DNSP, when assigning or reassigning a customer to a tariff class, must ensure the following:
   a. that customers with similar connection and usage profiles are treated equally
   b. that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

Reassignment of existing customers to another existing or a new tariff class during the 2011-15 regulatory control period

5. If a Victorian DNSP believes that an existing customer’s load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers in the customer’s existing tariff class, then it may reassign that customer to another tariff class. In determining the tariff class to which a customer will be reassigned, a DNSP must take into account paragraphs 3 and 4 of this appendix.

Objections to proposed tariff class assignments and reassignments

6. A Victorian DNSP must notify the customer concerned in writing of the tariff class to which the customer has been reassigned by it, prior to the reassignment occurring.
7. A notice under paragraph 6 must include advice that the customer may request further information from the DNSP and that the customer may object to the proposed reassignment. This notice must specifically include:
    a. either a copy of the DNSP's internal procedures for reviewing objections or the link to where such information is available on the DNSP's website
    b. that if the objection is not resolved to the satisfaction of the customer under the DNSP's internal review system, then to the extent that resolution of such disputes are within the jurisdiction of the Energy and Water Ombudsman (Victoria) the customer is entitled to escalate the matter to such a body
    c. that if the objection is not resolved to the satisfaction of the customer under the DNSP's internal review system and the ombudsman scheme noted in paragraph 7.b., then the customer is entitled to seek a decision of the AER through the dispute resolution process available under Part 10 of the NEL.
8. If, in response to a notice issued in accordance with paragraph 7, a Victorian DNSP receives a request for further information from a customer, then it must provide such information. If any of the information requested by the customer is confidential then it is not required to provide that information to the customer.
9. If, in response to a notice issued in accordance with paragraph 7, a customer makes an objection to a Victorian DNSP about the proposed reassignment, the relevant Victorian DNSP must reconsider the proposed reassignment, taking into consideration the factors in paragraphs 3 and 4 of this appendix, and notify the customer in writing of its decision and the reasons for that decision.
10. If a customer's objection to a tariff class reassignment is upheld by the relevant body noted in paragraphs 7 b and c, then any adjustment which needs to be made to tariffs will be done by the Victorian DNSP as part of the next annual review of prices.
11. If a customer objects to a Victorian DNSP about a tariff class assignment the DNSP must provide the information set out in paragraph 7 of this appendix and adopt and comply with the arrangements set out in paragraphs 8, 9 and 10 in respect of requests for further information by the customer and resolution of the objection.

System of assessment and review of the basis on which a customer is charged

12. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile, the Victorian DNSP must set out in its annual pricing proposal a method by which it will review and assess the basis on which a customer is charged.
13. If the AER considers that the method provided under paragraph 12 does not provide for an appropriate system of assessment and review by the DNSP of the basis on which a customer is charged, the AER may, at any time, request additional information or request that the relevant Victorian DNSP submit a revised pricing method.

14. If the AER considers that the DNSP's method for reviewing and assessing the basis on which a customer is charged (see paragraphs 12 and 13) is not reasonable it will advise the DNSP in writing.

Installation of interval meters and assignment of customers to TOU tariffs

15. If a DNSP installs an interval meter for an existing distribution customer the DNSP may reassign that distribution customer to a time of use distribution tariff subject to clause 9.1.14 of the Victorian Electricity Distribution Code in accordance with the AER's Final Decision: Interval Meter Reassignment Requirements published May 2009.

H Benchmarking

This appendix updates the benchmarking for capex and opex set out in appendix I of the draft decision with additional data received in the revised regulatory information notices (RINs) and the Victorian Distribution Network Service Providers' (DNSPs') revised proposals. It also sets out the AER's consideration of benchmarking issues that have been raised in the Victorian DNSPs' revised regulatory proposals and submissions to the revised proposals.

Appendix I of the draft decision set out in detail the AER's analysis of benchmarking including:

- *the role of benchmarking in distribution determinations*—the AER noted that the benchmark expenditure of an efficient firm is one of the ten factors to which it must have regard under the National Electricity Rules (NER) when assessing capex and opex. The AER considered that as the NER requires the AER to have regard to all factors when determining whether it is satisfied that proposed expenditure reflects the opex/capex criteria, the AER must use its discretion when determining how much weight to place on each of those factors including benchmarking. As discussed in the draft decision and in this appendix, the quality of the data available to the AER influences the weight the AER is able to place on benchmarking exercises.

  The AER also acknowledged the role benchmarking has played in price determinations by other regulators such as Ofgem and noted the differences in the regulatory regimes under which these regulators operate.

- *the various approaches and methodologies to benchmarking*—these include process approaches, programming techniques, econometric (parametric) techniques, bottom up benchmarking, ratio analysis, time series, trend analysis and performance monitoring.

- *the limitations of benchmarking*—while benchmarking is a useful tool in distribution determinations, the AER is aware of its limitations which include the sensitivity of results to the adopted methods, errors in assumptions used to normalise the data, and errors in selection of measured inputs or outputs. The AER also pointed out that the weight placed on benchmarking depends on the consistency and quality of input data.

The AER then outlined its approach to benchmarking for the Victorian distribution determination based on this analysis and the requirements under the NER.

The AER has adopted the analysis and approach detailed in appendix I of the draft decision for this final decision.

H.1 Victorian DNSP revised regulatory proposals

NERA Consulting (NERA) prepared a report for CitiPower and Powercor in which the efficiency of CitiPower's and Powercor's opex was assessed relative to other Australian DNSPs. NERA used a regression model to compare the Victorian DNSPs' normalised proposed total opex to the normalised total opex approved by the relevant regulator for other Australian DNSPs.[1] NERA included ratio analysis in its report.[2] The regression model and ratio analysis made use of various cost drivers.

Jemena Electricity Networks (JEN) engaged UMS Group (UMS) to benchmark its opex against comparable network utilities. UMS conducted various benchmarking analyses including:

- plotting opex against various drivers (customer numbers, line length, and energy delivered)—a regression line was derived for each cost driver comparison, with the line acting as a proxy average line
- time series and trend analysis
- analysis of non-field work and corporate overheads, and field work.[3]

United Energy obtained independent expert opinion from Philip Williams of Frontier Economics including a consideration of the AER's benchmarking analysis.[4]

Mr Williams commented that the AER did not use benchmarking to assess the efficiency or prudency of United Energy's proposed opex, which is not comparable to historical expenditure due to United Energy's new business model. Mr Williams also stated that the approach adopted by the AER is extremely high level and does not distinguish between efficiency and prudency.[5]

Mr Williams recommended that the AER estimate the costs that an efficient and prudent operator facing United Energy's conditions would incur in the forthcoming regulatory control period, placing greater weight on proper cost benchmarking and less on its current extrapolation approach. A proper cost benchmarking exercise would consider the nature, size and growth of United Energy's network over the relevant period compared to other similar DNSPs in Victoria and other National Electricity Market (NEM) jurisdictions.[6]

Mr Williams also acknowledged that a robust benchmarking assessment is difficult without robust data and requires consideration of many different variables.[7]

H.2 Submissions

The Energy Users Association of Australia (EUAA) stated that the AER did not meet its obligations under the NER to apply benchmarking in the assessment of capex and

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1 NERA, *Review of operating expenditure efficiency, A report for CitiPower-Powercor*, July 2010, pp. 14–17.
2 ibid., pp. 32–37.
3 Jemena Electricity Networks (JEN), *Revised Regulatory Proposal 2011–15*, 20 July 2010, appendix 6.11.
4 United Energy, *Revised Regulatory Proposal for Distribution Prices and Services, January 2011 - December 2015*, July 2010, pp. 17, 62.
5 Frontier Economics, *Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery*, July 2010, p. 12.
6 ibid., p. 15.
7 ibid.

opex.[8] The EUAA expressed the view that the benchmarking contained in appendix I of the draft decision does not meet the minimum standards for benchmarking. The EUAA set out its understanding of the AER's obligations on benchmarking in a submission to the Queensland distribution determination. If the AER's position on benchmarking differs from those detailed in the submission, the EUAA requested that the AER outline its position on benchmarking.[9]

The EUAA disagrees with the AER that the AER does not have the data to benchmark opex because the AER had developed a regression analysis for the New South Wales (NSW) and Queensland distribution determinations.[10] The EUAA stated that Ofgem has used benchmarking in its distribution determinations since 1999 and at the time had no better cost information available to it than the AER does now.[11]

EnergyAustralia submitted that benchmarking undertaken on aggregated and disaggregated capital expenditure is a misleading basis for comparing the relative efficiency of distributors. Capex is lumpy by nature and is driven by network specific factors such as available network capacity, asset condition, changes to licence conditions and the capital contributions framework applying in each jurisdiction. EnergyAustralia recommends that the AER focus its benchmarking on areas where meaningful comparisons can be made such as capital governance, policies and procedures, forecasting approaches and risk assessments, and unit costs of electrical equipment.[12]

EnergyAustralia stated that the purpose the horizontal axes in figure I.2 in appendix I of the draft decision serve are unclear. The use of line length in both the vertical and horizontal axes would likely lead to correlation issues with the analysis. The regression line does not appear to serve any purpose given the low R^2 values.[13]

EnergyAustralia considered that the AER's opex analysis underscores an inherent issue with benchmarking. The differences in outcomes reflect the unique characteristics of each business and the AER cannot draw meaningful conclusions on the relative efficiency of each business from this level of analysis. This is because different methods and approaches yield different outcomes. The proper role of benchmarking is therefore to identify areas for further examination by the AER.[14]

The Consumer Action Law Centre (CALC) recommended that the AER gather data from the industry to undertake a multi-lateral total factor productivity (TFP) study of the Australian DNSPs to limit the distortions of partial benchmarking.[15]

8 EUAA, *Submission to the AER—AER Draft Determination on Victorian electricity distribution prices for the period 2011–2015 and distributors' revised proposals*, 19 August 2010, p. ii.
9 ibid., p. 20.
10 ibid.
11 ibid., p. 21.
12 EnergyAustralia, *EnergyAustralia submission on AER draft regulatory determination for Victorian distributors (cover letter)*, 19 August 2010, p. 4; EnergyAustralia, *EnergyAustralia's submission on AER's draft regulatory determination for Victorian distributors*, 19 August 2010, p. 3.
13 EnergyAustralia, *Submission to the AER*, 19 August 2010, pp. 3–4.
14 ibid., p. 16.
15 Consumer Action Law Centre, *Submission to the AER's Victorian Draft Distribution Determination 2011–2015*, Appendix 1, 19 August 2010, p.5.

The Energy Users Coalition of Victoria (EUCV) commented that external benchmarking can indicate whether or not proposed base year opex is efficient, particularly where a business changes its approach to opex (as United Energy proposes). With the potential use of TFP in regulatory reviews the EUCV recommended some back checking of opex through TFP or some similar benchmarking technique.[16]

H.3 AER issues and considerations

H.3.1.1 Victorian DNSP revised regulatory proposals

The implications of the NERA report are discussed in chapter 6 of this final decision.

Regarding Mr Williams' report, the AER considers that the benchmarking it has undertaken in assessing United Energy's proposed opex meets the requirement of clause 6.5.6(e)(4) of the NER. The opex benchmarking detailed in appendix I of the draft decision, and reproduced with updated data in section H.4.2 below, takes into account the nature of United Energy's and other Victorian DNSPs' networks having had regard to characteristics such as customer numbers and density, peak demand and energy consumption.

As detailed in the draft decision, clause 6.5.6(e)(4) is one of ten operating expenditure factors the AER must have regard to in assessing United Energy's proposed opex. The AER's consideration of benchmarking in regard to the assessment of United Energy's opex is discussed in chapter 7 of this final decision. This chapter also addresses Mr Williams' comments regarding the distinction between efficiency and prudency.

H.3.1.2 Submissions

As stated in the draft decision the AER does not consider that the role it has defined for benchmarking is inconsistent with the rules, as the EUAA asserted. The AER acknowledges that the NER requires the AER to have regard to the benchmark opex/capex that would be incurred by an efficient DNSP over the regulatory control period. The AER considers that it has had regard to this factor when coming to its conclusions on the opex and capex allowances as it has:

- conducted its own benchmarking analysis (see section H.4 of this final decision and appendix I of the draft decision)
- has been informed by the benchmarking analysis of its consultant Nuttall Consulting
- has examined and considered the consultants’ reports regarding benchmarking submitted by the Victorian DNSPs in their initial and revised regulatory proposals.

Benchmarking was but one component of the AER’s comparative analysis. As stated in the draft decision the AER does not come to a separate view on each and every opex and capex factor in isolation. Rather, the AER considers all the opex/capex factors and takes a holistic approach to determining reasonable forecasts of

[16] EUCV, *Submission to the AER - 2010 AER review of Victorian Electricity DBs, EUCV response to AER draft decision*, August 2010, p. 39.

opex/capex over the regulatory control period that reflects the opex/capex criteria. The AER considers that as the NER requires the AER to have regard to all factors when determining whether it is satisfied that proposed expenditure reflects the opex/capex criteria, the AER must use its discretion when determining how much weight to place on each of those factors including benchmarking. Chapters 7 and 8 discuss the AER's consideration of benchmarking analysis in its assessment of proposed opex and capex respectively.

In relation to the EUAA's comment on benchmarking undertaken by Ofgem, the AER points to differences with the Australian regulatory regime and in Australian DNSPs. These differences need to be considered when coming to a view of the applicability of the approach used by Ofgem in its recent decisions to the Australian regulatory regime, which include:

- the discretionary regulatory regime Ofgem operates under in the UK in comparison to the relatively prescriptive regime the AER operates under in Australia

- relatively homogenous Distribution Network Operators (DNOs) in the UK that Ofgem regulates in comparison to the comparatively heterogonous DNSPs regulated by the AER in Australia.

While Ofgem may have used benchmarking since 1999, the extent to which benchmarking was utilised in regulatory decisions at the time is unclear. In any case, Ofgem had been regulating distribution businesses for approximately 10 years by the time it began using more limited forms of benchmarking in 1999. By comparison, the AER began regulating DNSPs in 2008 with the Queensland, South Australian and Victorian distribution determinations being the first under the NER (the NSW and Australian Capital Territory distribution determinations were made under the transitional NER). Prior to this, DNSPs were regulated by the respective NEM jurisdictional regulators where information collection requirements differed significantly between NEM jurisdictions. The AER notes that the Utility Regulators Forum (URF) established a national reporting framework that set out to remedy the inconsistencies caused by the different jurisdictional legal frameworks and the varying information requirements.[17] However this framework has no legal status that requires regulators or DNSPs to adhere to the templates, which compromises the integrity of the data. As the national regulator, the AER is now developing, and will be applying, a more consistent information and reporting framework that will be used, amongst other things, in future price reviews.

Regarding EnergyAustralia's submission, the trend lines in figure I.2 of appendix I of the draft decision act as the proxy average firm and provide some guidance when comparing the relative efficiency of DNSPs.

Regarding submission from the CALC and the EUCV, the AER would consider the use of TFP analysis in future reviews. This would be subject to, among other things, availability and quality of data, changes to the regulatory regime and whether or not TFP is the most appropriate methodology compared to other benchmarking

[17] URF, *National regulatory reporting for electricity distribution and retailing businesses*, URF discussion paper, March 2002.

methodologies. The AER notes that the Australian Energy Market Commission (AEMC) is currently reviewing the use of TFP for the determination of prices and revenues.[18]

H.3.1.3 Summary

The AER recognises that it is required to have regard to benchmark expenditure (opex and capex) that would be incurred by an efficient DNSP over the regulatory control period. The AER also notes that in considering the opex and capex factors, it becomes a matter of judgement as to the weighting given to the factors. It is not possible to view and come to a conclusion on each of the opex and capex factors in isolation. The AER considers all the opex and capex factors, and makes judgements based on a holistic approach.

The AER must come to a conclusion on the allowance to be given for opex and capex that is specific to each DNSP, taking into account benchmark costs that would be incurred by an efficient DNSP. The AER considers that, in addition to any established benchmark costs, under clauses 6.5.6(c)(2) and 6.5.7(c)(2), a DNSP's circumstances are also relevant. When considering the allowance for each DNSP, the opex and capex factors do not stand alone but are considered together.

The AER considers that at the current time it cannot establish revenue allowances based primarily on the outcome of comparative benchmarking against other firms. When more standardised and appropriate data becomes available as a result of the application of the AER's new framework, noted above, and benchmarking models give more consistent results, the weighting given to top down benchmarking as a part of the AER’s comparative analysis will likely increase.

However, in addition to the overarching regulatory framework and requirements of the NER under which the AER operates, there are inherent limitations in benchmarking techniques which must be recognised when developing and using benchmark approaches.

These considerations were discussed in detail in appendix I of the draft decision.

Nevertheless, even at this stage, the AER considers that a number of high level patterns are evident in the analysis. These high level patterns have been taken into account in reaching a view on the appropriate levels of opex and capex.

H.4 AER final decision benchmarking

H.4.1 Capex benchmarking

The following section updates the various benchmarking techniques used to inform the AER’s assessment of capex with data from the revised RINs and the Victorian DNSPs' revised regulatory proposals.

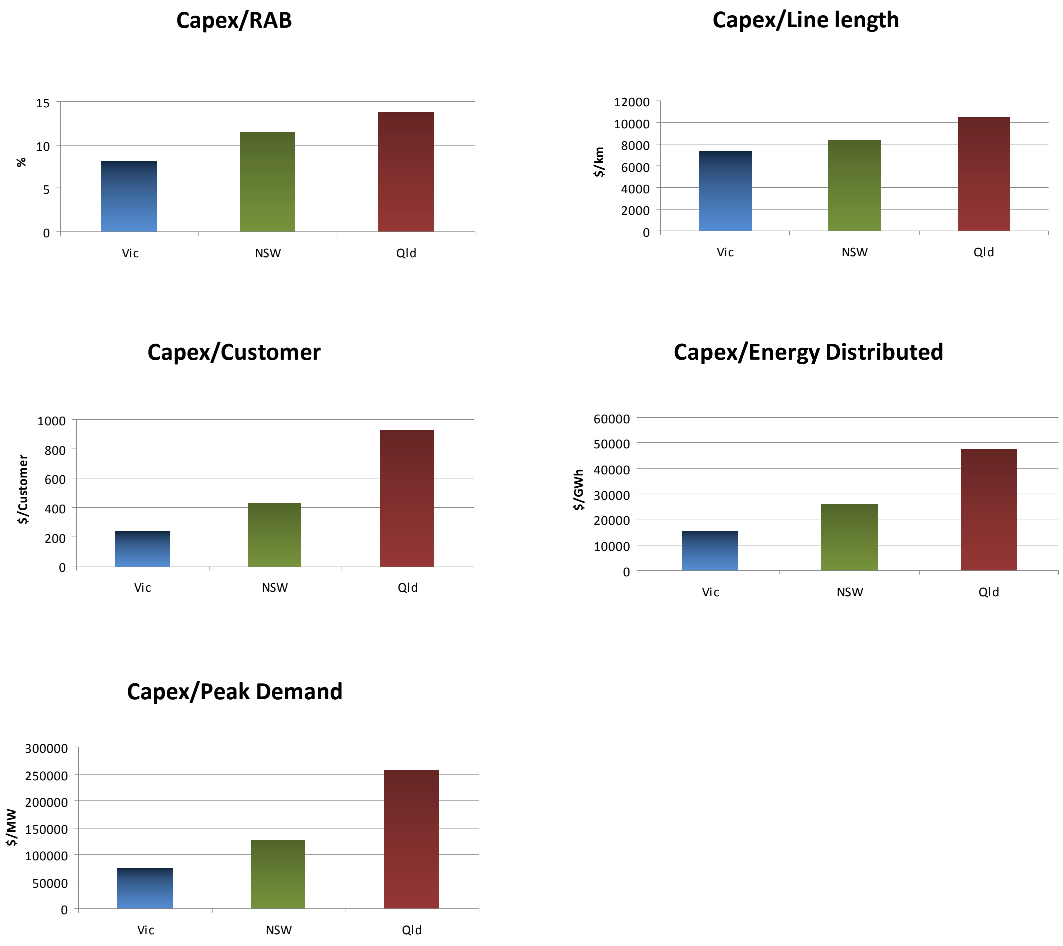
The AER and Nuttall Consulting jointly conducted ratio analysis of the Victorian DNSPs to test their efficiency against each other and against other DNSPs in the

[18] www.aemc.gov.au

NEM. The analysis compared DNSPs across a number of ratios. The analysis uses a number of comparison denominators to compare DNSPs.

The ratio analysis used the three states with customer numbers in excess of one million—Victoria, NSW and Queensland. The AER also compared the level of recent historical capital expenditure for the state of Victoria and the individual DNSPs against other states and their counterparts, using various parameters to normalise the results (for example customers per km of line).

Figure H.1 Historical capex analysis by state



Source: AER analysis

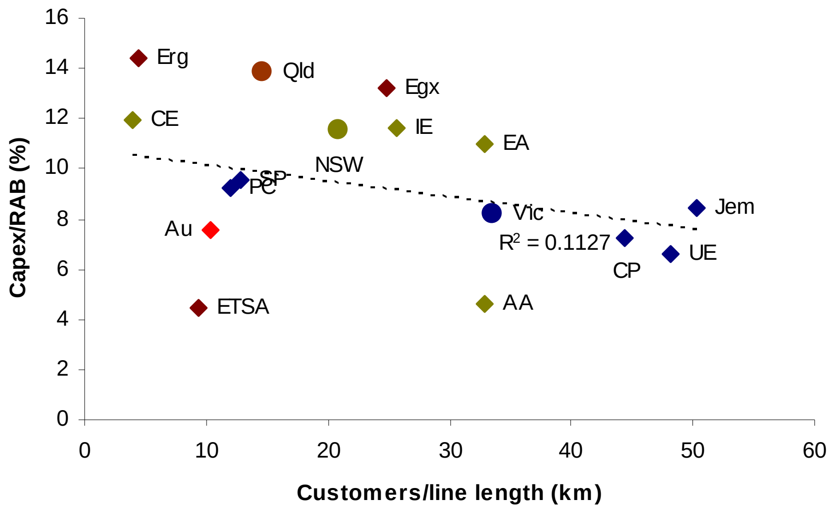
The above analysis shows that Victorian DNSPs compare well when overall capex is compared with that of Queensland and NSW DNSPs.[19]

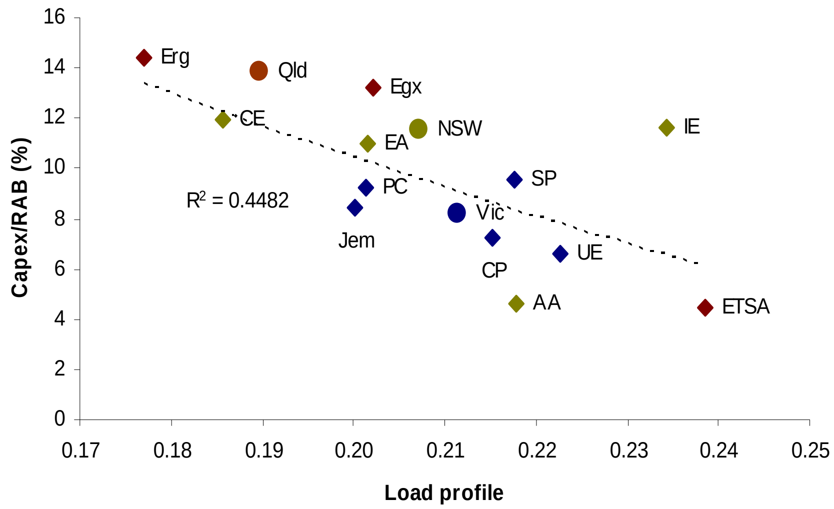
The AER notes that Nuttall Consulting concluded that:

[19] These states are considered most comparable based on the number of customers served and that each state has more than one supplier. This analysis has not been further adjusted to account for other factors such as geographical size, etc.

- this range of measures would suggest that the overall Victorian levels of capex are not inefficient when compared with Queensland and NSW
- the overall level of capex in Victoria as revealed in the previous five years also appears to be efficient relative to its peers.[20]

Figure H.2 Historical capex analysis by DNSP





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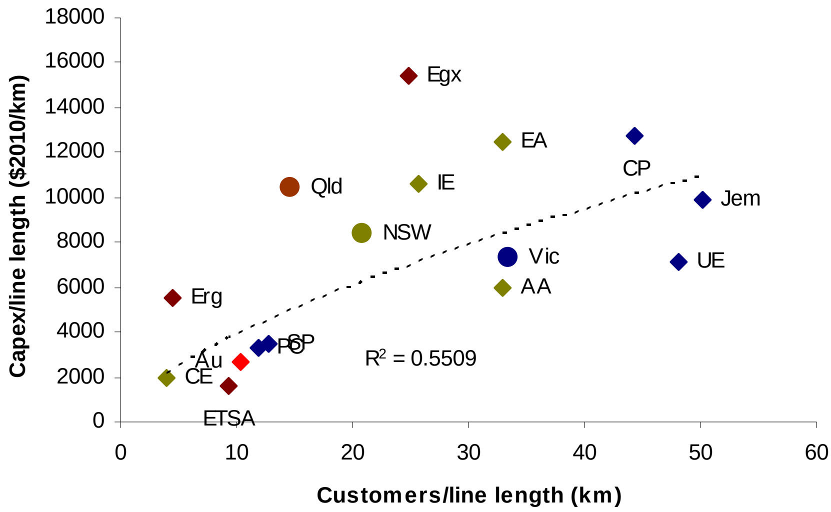
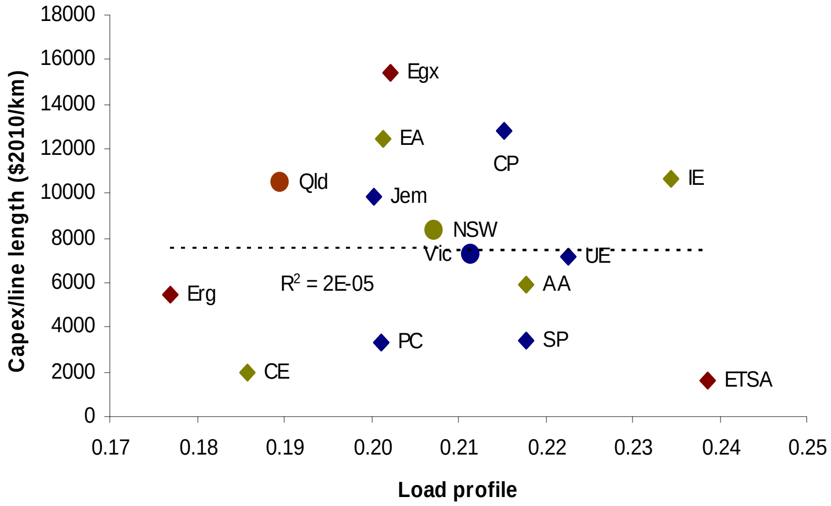
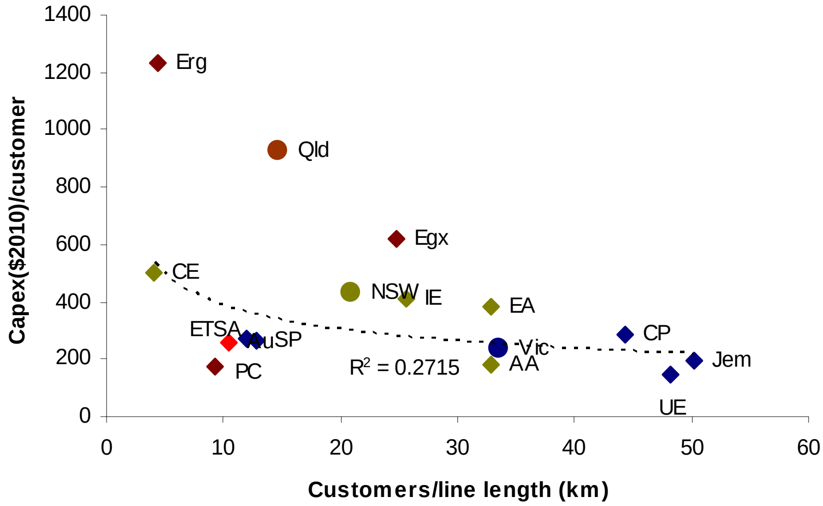
20 Nuttall Consulting, *Report—Capital Expenditure Victorian Electricity Distribution Revenue Review*, 4 June 2010, p. 21; Nuttall Consulting, *Report—Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 19.



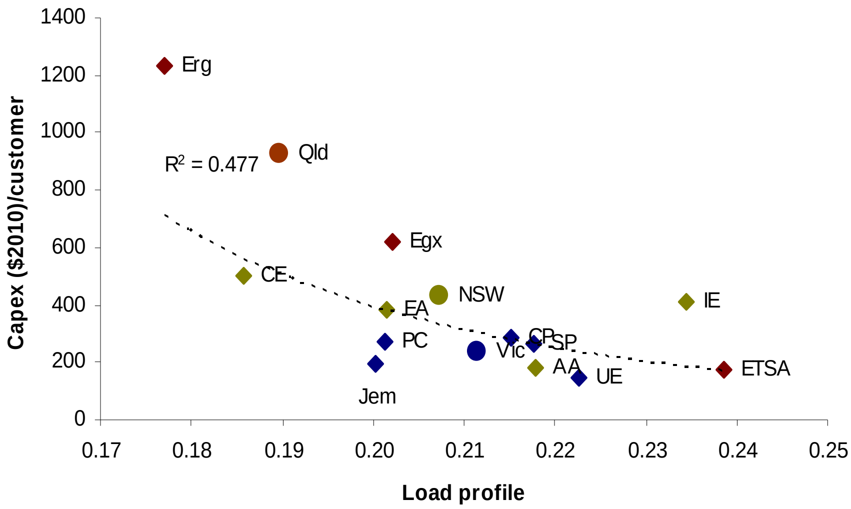
Capex/line length ($2010/km)
Customers/line length (km)
Egx
EA
CP
Qld
IE
Jem
NSW
Vic
UE
AA
Erg
SP
PC
Au
CE
ETSA
R² = 0.5509

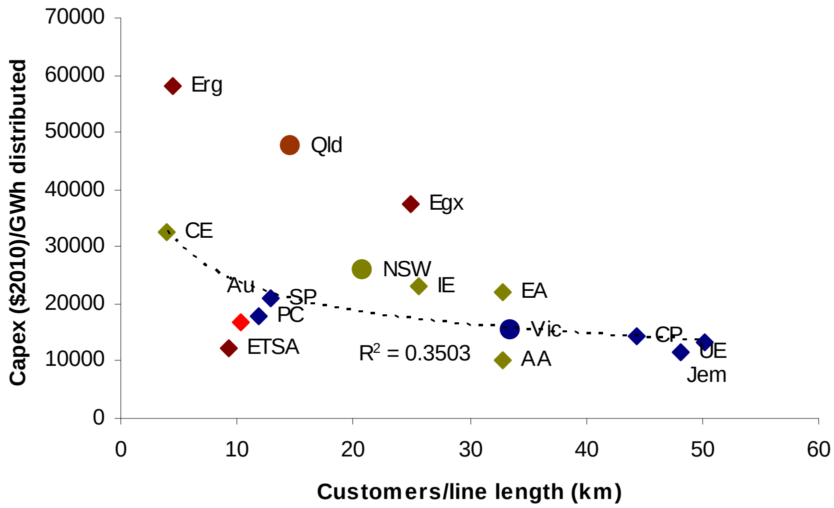


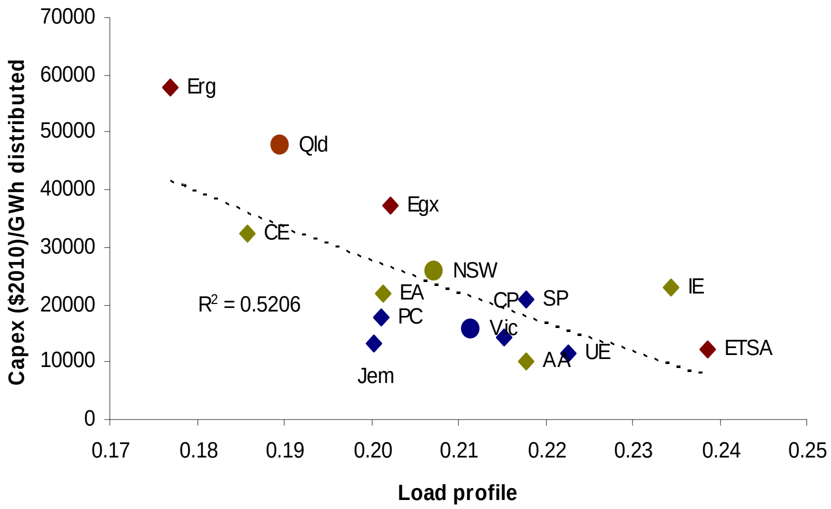
Capex/line length ($2010/km)
Load profile
Egx
EA
CP
Qld
IE
Jem
NSW
Vic
UE
AA
Erg
R² = 2E-05
PC
SP
CE
ETSA

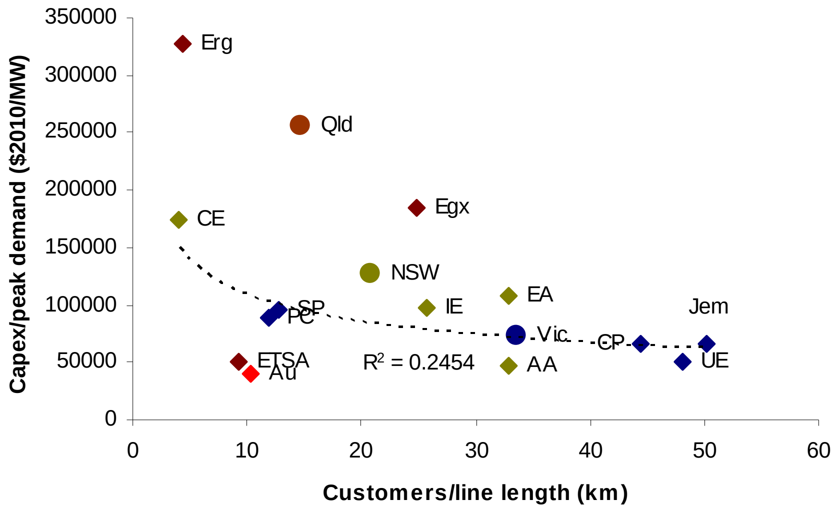


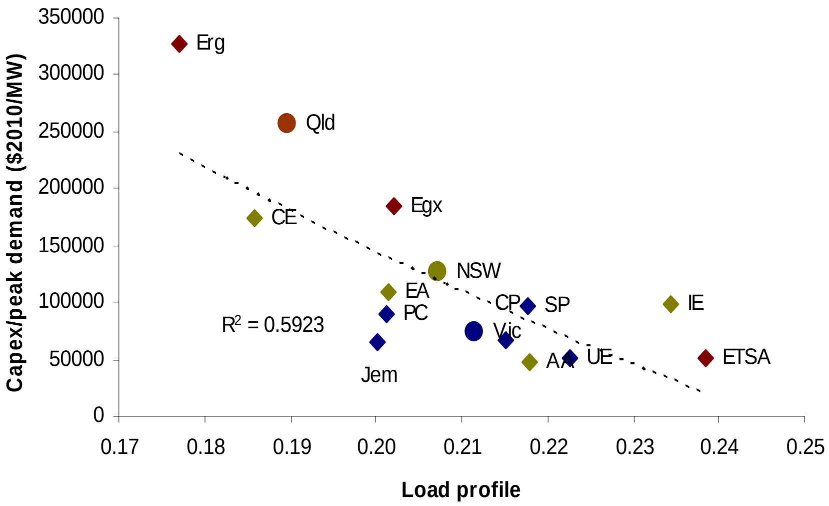
Capex($2010)/customer
Customers/line length (km)
Erg
Qld
Egx
CE
NSW
IE
EA
ETSA
SP
CP
Vic
Jem
AA
PC
R² = 0.2715
UE


Capex ($2010)/customer
Load profile
R² = 0.477
Erg
Qld
Egx
CE
NSW
IE
EA
PC
Vic
CP
SP
AA
UE
ETSA
Jem


Capex ($2010)/GWh distributed
Customers/line length (km)
R² = 0.3503
Erg
Qld
Egx
CE
NSW
IE
EA
Au
SP
PC
ETSA
Vic
CP
UE
AA
Jem


Capex ($2010)/GWh distributed
Load profile
R² = 0.5206
Erg
Qld
Egx
CE
NSW
IE
EA
PC
CP
SP
Vic
AA
UE
ETSA
Jem





Note: AA – Actew/AGL, AGLE – JEN (formerly AGL and Alinta), Au – Aurora Energy, CE – Country Energy, CP – CitiPower, EA – EnergyAustralia, Egx – Energex, Erg – Ergon Energy, ETSA – ETSA Utilities, IE – Integral Energy, PC – Powercor, SP – SP AusNet, UE – United Energy

Note: Load profile is defined as MW/GWh.

Note: Outliers have been removed.

Source: AER analysis

As with the draft decision analysis, the above charts appear to indicate that the overall level of capex for the Victorian DNSPs is broadly below the level of comparable DNSPs.

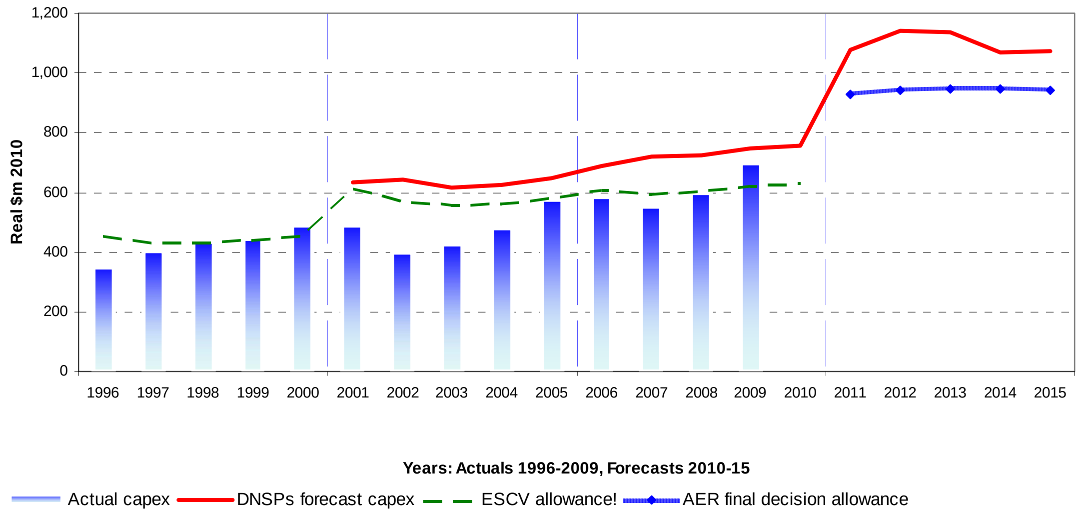
As the data used in this analysis has not been corrected for differences that exist in the regulatory environment historically, asset classifications, network maturity and geographical factors between jurisdictions, caution must be used when applying this analysis more broadly.

Trend analysis capex

Figures H.3 to H.8 below show the AER's trend analysis of the Victorian DNSPs' past capital expenditure. They have been updated using data from the revised RINs and the Victorian DNSPs' revised regulatory proposals. This trend analysis was undertaken to test the forecasting performance of the Victorian DNSPs as is required by the NER, to assess their actual expenditure in comparison to these forecasts, and assess trends in the Victorian DNSPs' capex.

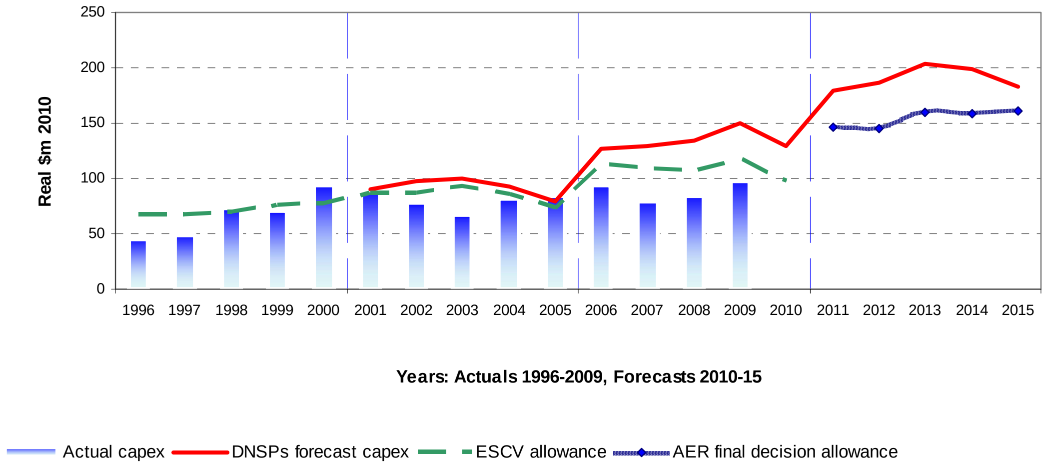
Figure H.3 compares the Victorian DNSPs' actual capex against their forecast capex. The AER's trend analysis indicates that the Victorian DNSP's past forecasts have been high and that they are again forecasting significant growth in their spending in the forthcoming regulatory control period. Actual expenditure on the other hand has tended to be below both their proposed expenditures and the benchmark expenditures set by the Essential Services Commission of Victoria (ESCV) (see figure H.4 to figure H.8).

Figure H.3 Victorian industry capex trend analysis



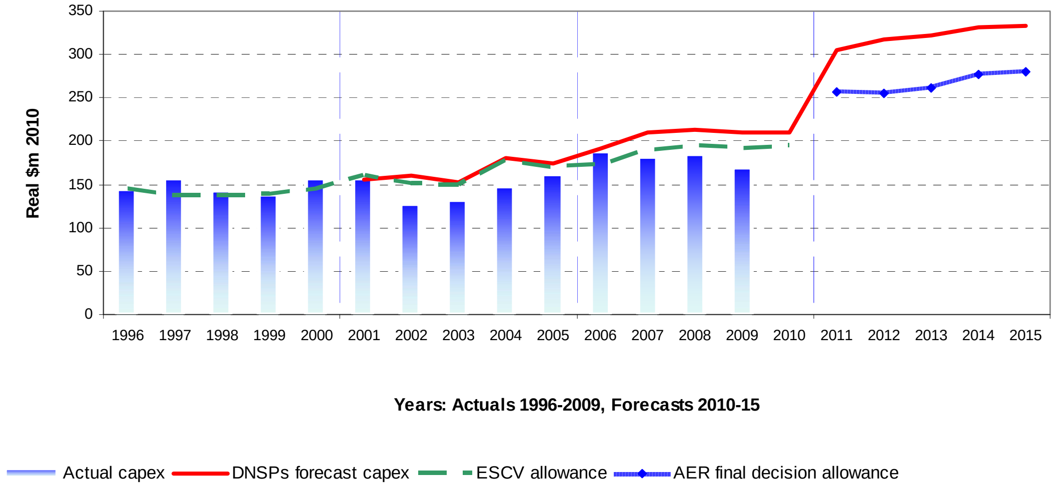
Source: AER analysis

Figure H.4 CitiPower capital expenditure analysis



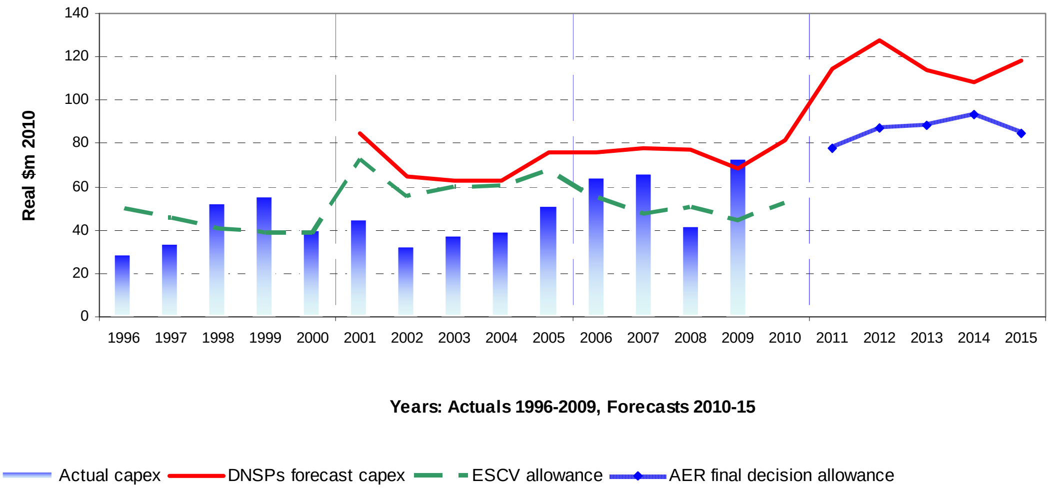
Source: AER analysis

Figure H.5 Powercor capital expenditure analysis



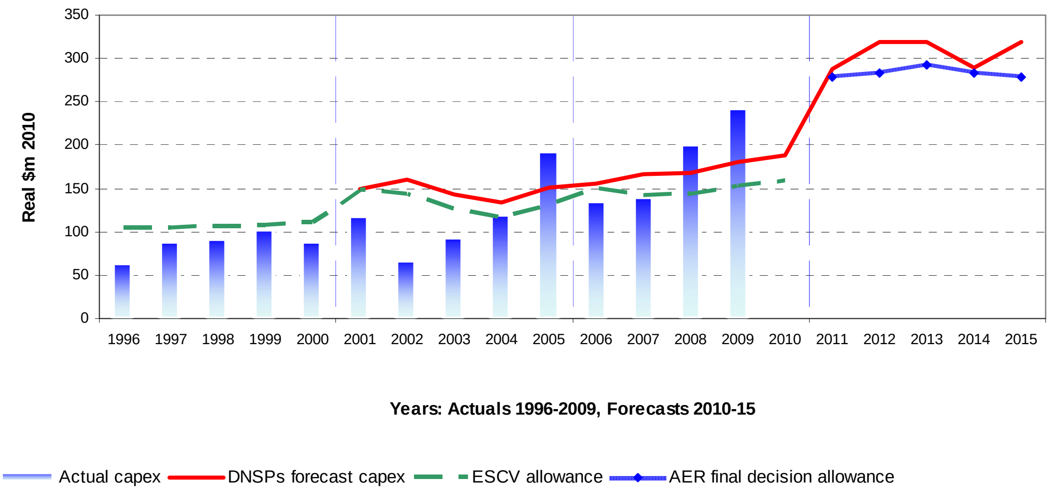
Source: AER analysis

Figure H.6 JEN capital expenditure analysis



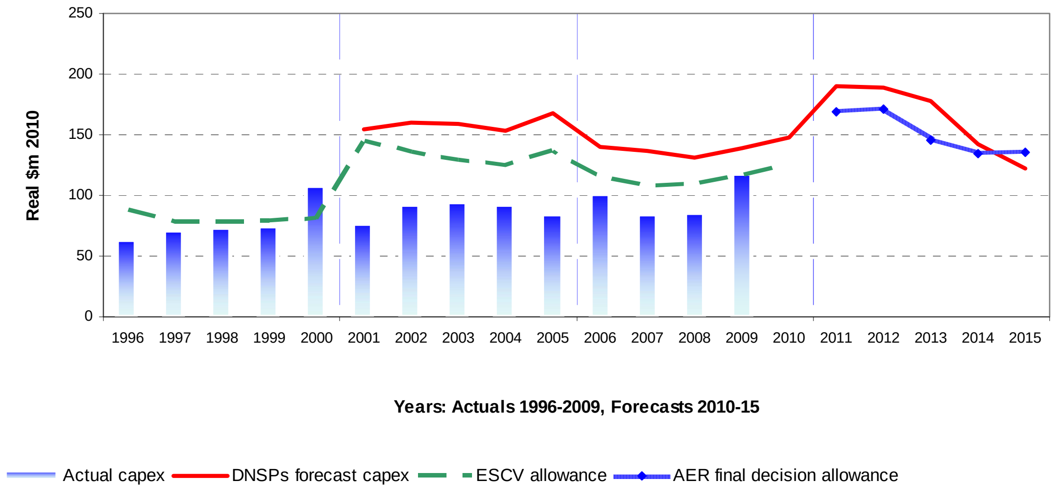
Source: AER analysis

Figure H.7 SP AusNet capital expenditure analysis



Source: AER analysis

Figure H.8 United Energy capital expenditure analysis



Source: AER analysis

Replacement modelling

The AER's consideration of the Nuttall Consulting replacement modelling is detailed in chapter 8 of this final decision.

Process review

Another element of Nuttall Consulting's review involved process benchmarking through reviewing the capital governance practices of the Victorian DNSPs.

The following table shows the assessed ratings for each DNSP for each assessment element. This analysis was detailed in the draft decision and has been adopted for the final decision. Details of Nuttall Consulting's further assessment can be found in chapter 2 of the Nuttall Consulting report.[21]

[21] Nuttall Consulting report, 4 June 2010, chapter 2.

Table H.1 Governance review summary[22]

DNSP	Policy and strategy	Asset management information	Risk management	Capex planning	Implementation and operation	Management review and continual improvement
CitiPower	3 - high	3 - high	2 - partial	3 - high	3 - high	3 - high
Powercor	3 - high	3 - high	2 - partial	3 - high	3 - high	3 - high
JEN	3 - high	2 - partial	3 - high	3 - high	3 - high	3 - high
SP AusNet	3 - high	3 - high	3 - high	3 - high	2 - partial	2 - partial
United Energy	3 - high	3 - high	3 - high	3 - high	3 - high	2 - partial

Source: Nuttall Consulting report, 4 June 2010, p. 42.

H.4.2 Opex benchmarking

This section updates the opex benchmarking techniques detailed in section I.4.2 of the draft decision with data from the revised RINs and the DNSPs' revised regulatory proposals. It is important to note that the AER's assessment must be viewed in the context of the opex objectives, criteria and factors, of which, benchmarking (clause 6.5.6(e)(4)) is but one element.

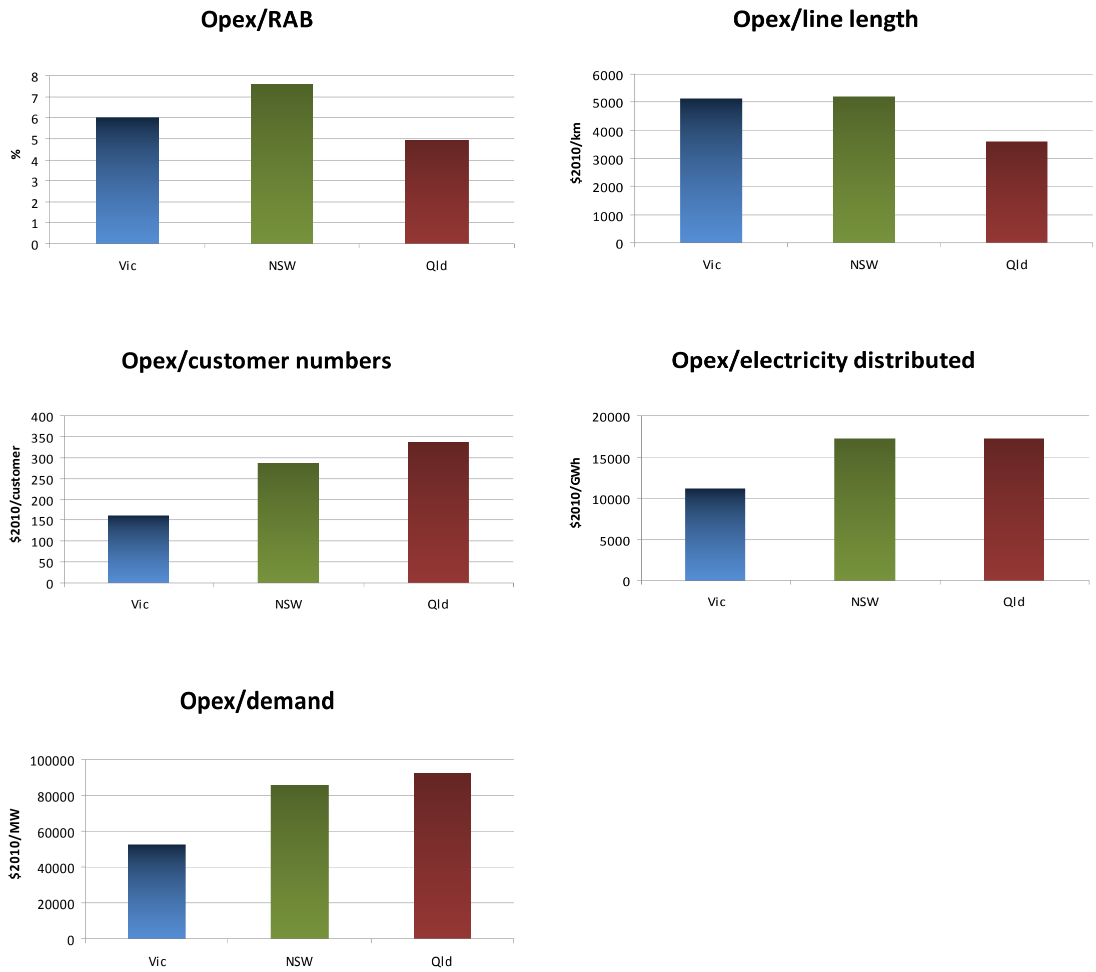
Ratio analysis opex

The following section updates the various benchmarking techniques used in the draft decision to inform the AER's assessment of opex with data from the revised RINs and the DNSPs' revised regulatory proposals.

The ratio analysis used the three states with customer numbers in excess of one million—Victoria, NSW and Queensland. The AER compared the level of recent historical opex for the state of Victoria and the individual DNSPs against other states and their counterparts, using various parameters to normalise the results (for example customers per km of line).

[22] Assessments against each framework element are uniformly acceptable for each DNSP, with a rating of 3 - high being indicative of compliance. Thus, it would be expected that a DNSP that applies its documented capital governance processes and practices would be expected to deliver efficient outcomes for its stakeholders. Where "2 - partial" ratings have been assessed, Nuttall Consulting considered that any shortfall may simply be a matter of documentation rigour within the submitted material, as opposed to any material gap in the DNSP's processes or practices.

Figure H.9 Historical opex analysis by state

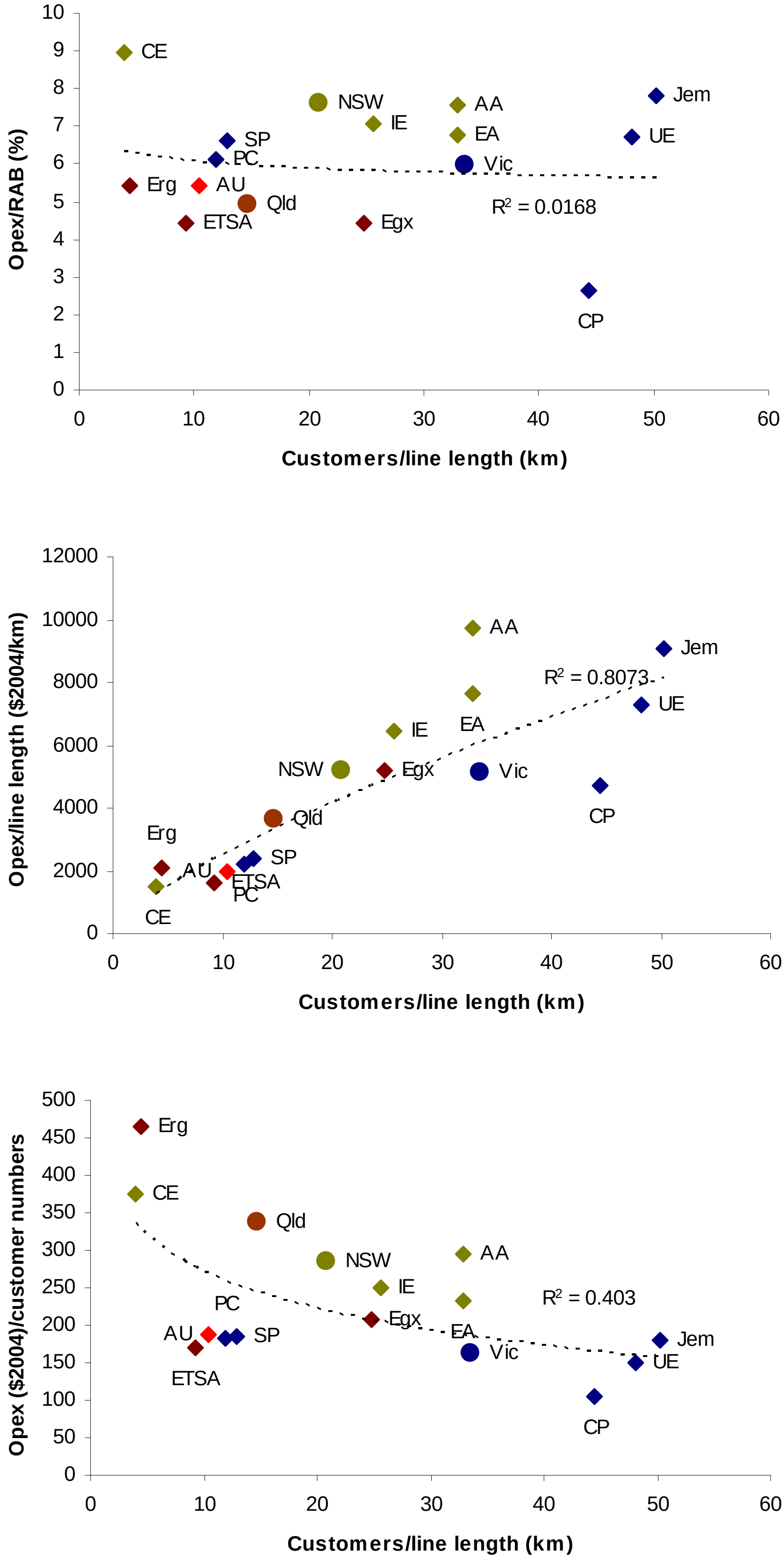


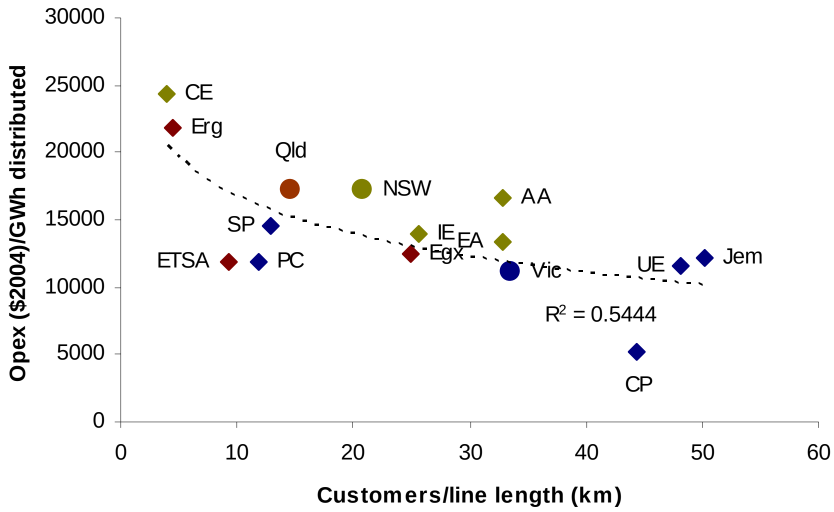
Source: AER analysis

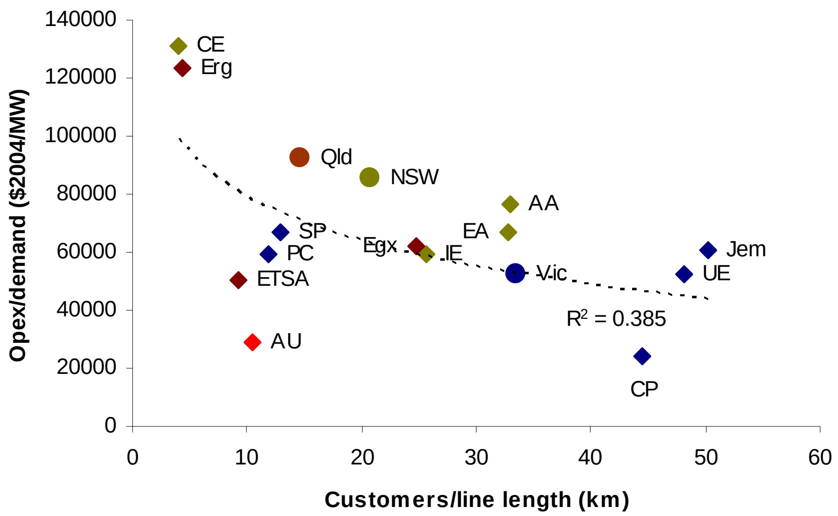
The above analysis shows that Victorian DNSPs compare well when overall opex is compared with that of the Queensland and NSW DNSPs.[23]

[23] These states are considered most comparable based on the number of customers served and that each state has more than one supplier. Note however, these charts have not been corrected for factors including differences in RAB size and line length, etc.

Figure H.10 Historical opex analysis by DNSP







Note: AA – Actew/AGL, AGLE – JEN (formerly AGL and Alinta), Au – Aurora Energy, CE – Country Energy, CP – CitiPower, EA – EnergyAustralia, Egx – Energex, Erg – Ergon Energy, ETSA – ETSA Utilities, IE – Integral Energy, PC – Powercor, SP – SP AusNet, UE – United Energy

Source: AER analysis

The above charts appear to indicate that the overall level of opex for the Victorian DNSPs is broadly below the level of comparable DNSPs.

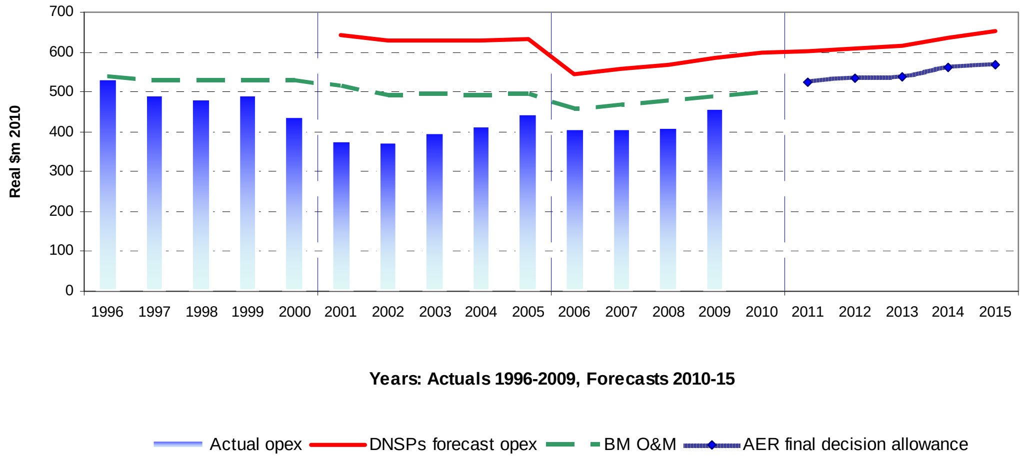
As the data used in this analysis has not been corrected for differences that exist in the regulatory environment, asset classifications, network maturity and geographical factors between jurisdictions, caution must be used when applying this analysis more broadly.

Trend analysis opex

Figures H.11 to H.16 below show the AER's trend analysis of the Victorian DNSPs' past opex. They have been updated using data from the revised RINs and the Victorian DNSPs' revised regulatory proposals. This trend analysis was undertaken to test the forecasting performance of the Victorian DNSPs as is required by the NER to assess their actual expenditure in comparison to these forecasts, and assess trends in the Victorian DNSPs' capex.

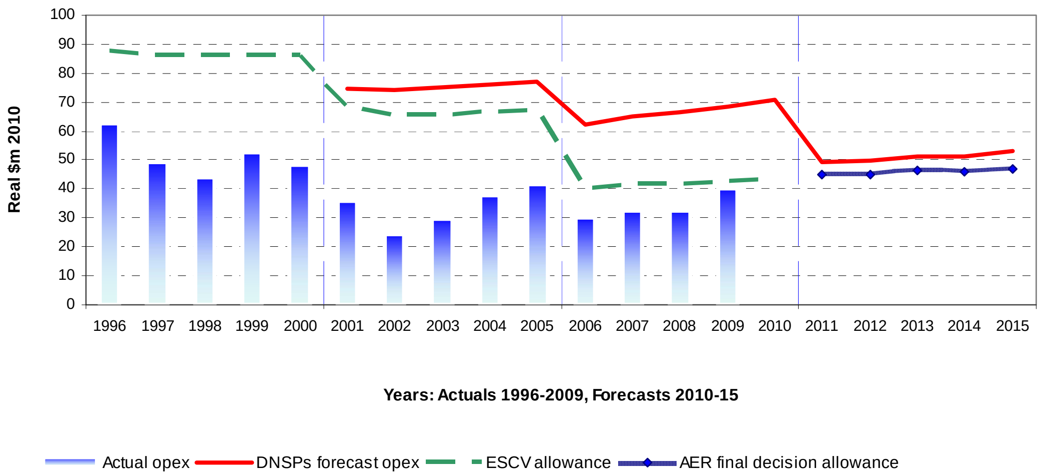
Figure H.11 compares the Victorian DNSPs' actual opex against their forecast opex. The AER's trend analysis indicates that the Victorian DNSP's past forecasts have been high and that they are again forecasting significant growth in their spending in the forthcoming regulatory control period. Actual expenditure on the other hand has tended to be below both their proposed expenditures and the benchmark expenditures set by the ESCV (see figure H.12 to figure H.16).

Figure H.11 Victorian industry opex trend analysis



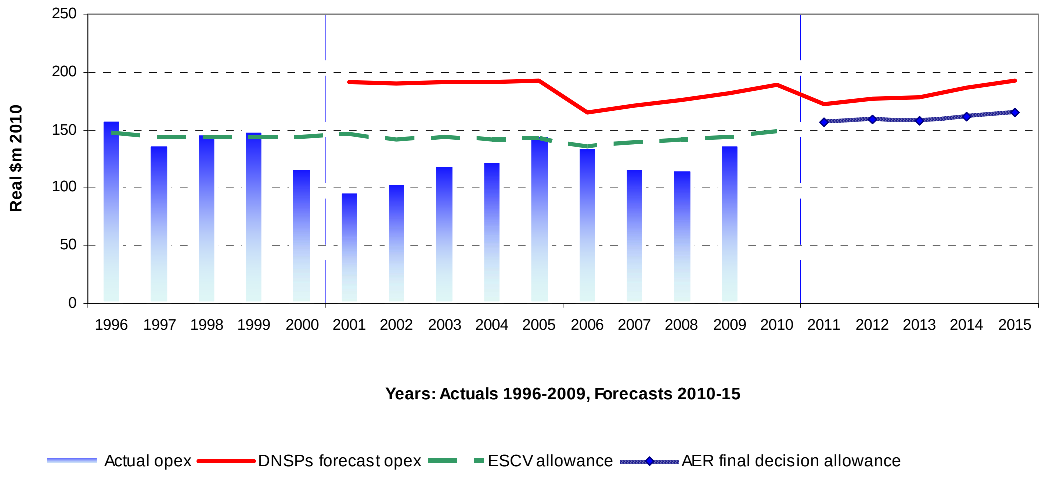
Source: AER analysis

Figure H.12 CitiPower opex analysis



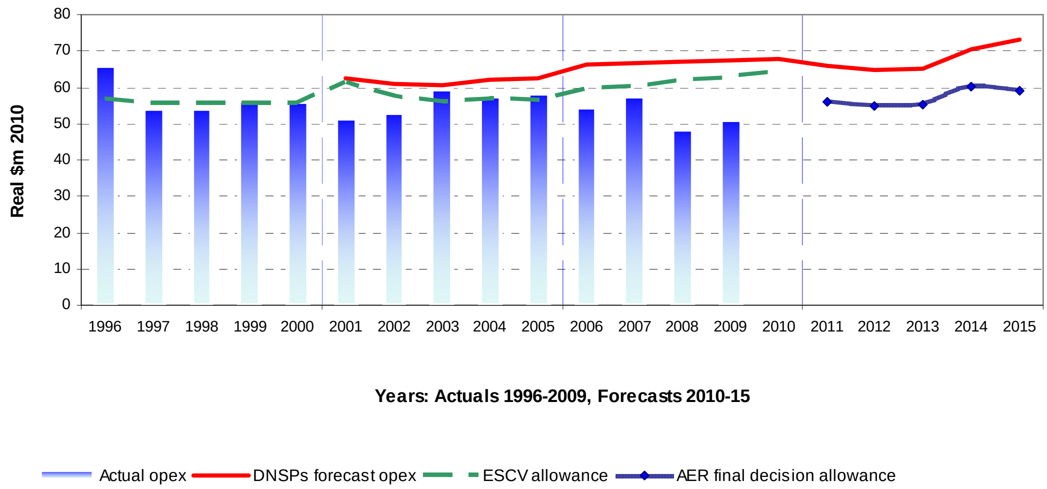
Source: AER analysis

Figure H.13 Powercor opex analysis



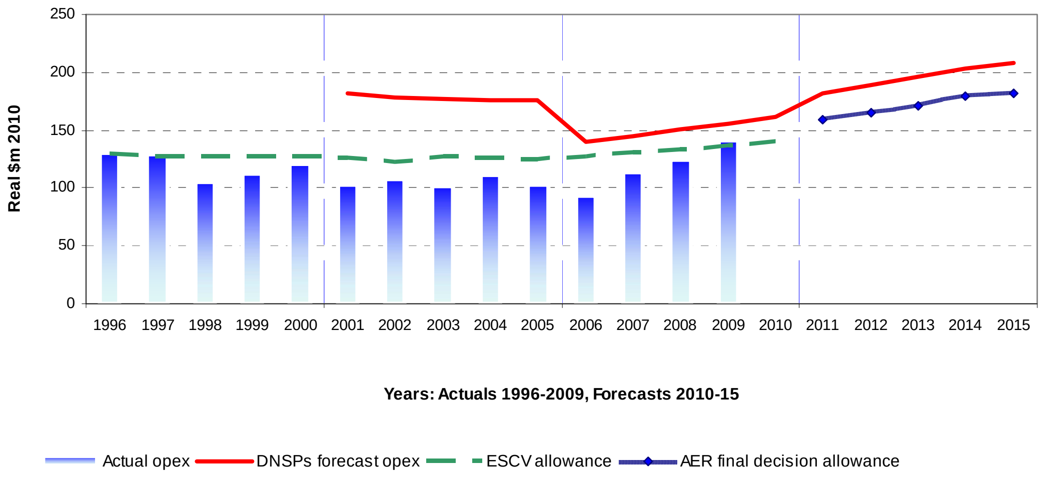
Source: AER analysis

Figure H.14 JEN opex analysis



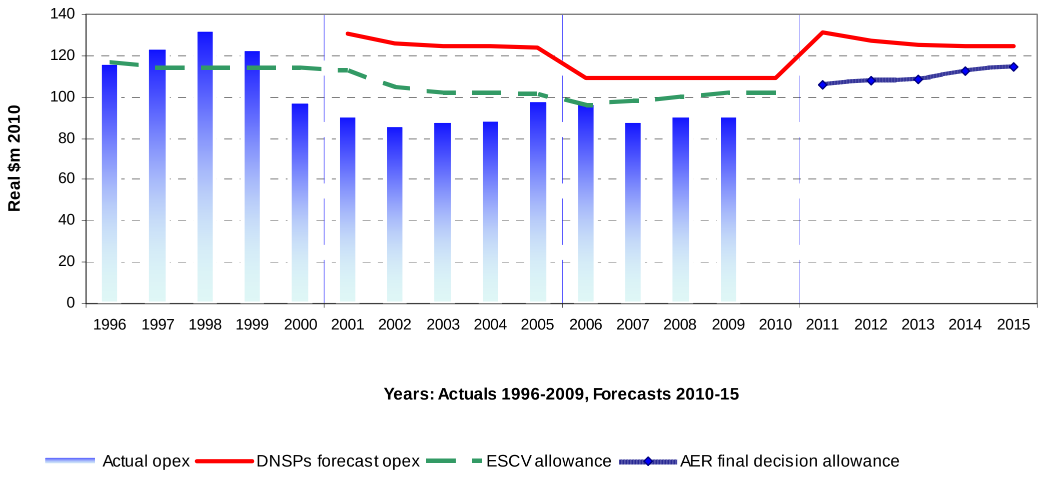
Source: AER analysis

Figure H.15 SP AusNet opex analysis



Source: AER analysis

Figure H.16 United Energy opex analysis



Source: AER analysis

The analysis confirms that the Victorian DNSPs' ‘revealed’ actual costs generally sit below the approved efficient regulatory benchmarks. The AER considers that the approach of using adjusted actual base year revealed costs results in forecast levels of opex which are likely to reasonably reflect the opex criteria in clause 6.5.6(c) of the NER.[24]

This analysis suggests that the Victorian DNSPs' operating expenditure forecasts tend to systematically over estimate actual operating expenditure.

Caution should however be used with this analysis of different jurisdictions as the data used has not been corrected for differences that may exist in the regulatory environment, asset classifications, network maturity and geographical factors.

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24 Refer to chapter 7 of this final decision.

The analysis presented in this section, when viewed together is informative in that it enables the AER to draw conclusions about the performance of the Victorian DNSPs (actual opex) against efficient regulatory benchmarks (trend analysis) and the performance of the Victorian DNSPs against their peers (comparative ratio analysis).

H.5 AER conclusion

The AER considers that it has had regard to benchmarking, and utilised the information gained from its models in a suitable manner, considering the limitations imposed by the current data.

As required under clauses 6.5.6(e) and 6.5.7(e) of the NER, the AER has had regard to benchmark expenditure (opex and capex) that would be incurred by an efficient DNSP over the regulatory control period in coming to its conclusions on the forecast opex and capex allowances of the Victorian DNSPs. The AER will continue to develop more robust benchmarking techniques, and improve the quality of available information in order to expand its usage of benchmarking in evaluating opex and capex proposals.

I United Energy operating and maintenance forecast

I.1.1 Introduction—Background on United Energy's transformation to a new business model

United Energy's current business model, as noted in the draft decision, is centred on:

- a small management structure that conducts strategic management and corporate governance activities both within and through services provided by its parent entity Diversified Utility Energy Trust (DUET)[1]
- a single outsourced contract—its operating services agreement (OSA)—under which the asset management, planning, construction and maintenance of its network is outsourced to Jemena Asset Management (JAM), which is ultimately owned by United Energy's minority shareholder (Singapore Power).[2]

However, United Energy stated that the current OSA between United Energy and JAM expires on 31 July 2011 (six months into the forthcoming regulatory period) and United Energy does not intend to renew this agreement. Rather, United Energy stated that it is in the process of transforming to a substantially different business model with much of the management, administrative and planning activities being internalised and performed by United Energy (or more precisely, by parties related to United Energy).

Accordingly, the first six months of United Energy's opex forecast in its regulatory proposal are based on its current business model, whereas the remainder of the forecast is based on expected costs under its new business model. That said, the AER noted that United Energy has begun to incur transformational costs related to the transfer to its new business model, which are reflected in its current actual costs and the 2011–15 regulatory control period forecasts.

United Energy stated that its 'aggressive' approach to outsourcing pursued under its current business model has achieved significant cost reductions and service improvements.[3] According to United Energy, one of those benefits has been its shielding from cost increases in recent years due to the mostly fixed nature of the opex charge paid to JAM. However, United Energy considered that there are a number of problems with its current business model which its new model seeks to address. These included:

1 The AER understands that until recently, United Energy did not directly employ any staff. United Energy has until recently sourced only a limited number of management services from a related party—Pacific Indian Energy Services (PIES)—and certain management, investment and financial services from its majority shareholder DUET and a related party—AMP Capital Investors (AMPCI). PIES is jointly owned by United Energy, Multinet and Westnet Gas. United Energy, Multinet and Westnet Gas are both the owners and customers of PIES.

2 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, November 2009, p. xvii.

3 United Energy, *Regulatory proposal*, November 2009, p. xiv.

- the reliance on a single contractor
- a lack of strategic capacity and control over its network
- a lack of transparency over costs and
- the 'distrust' of its business model by the regulator.[4]

United Energy submitted that its new business model involves it taking a much greater hands-on approach to managing and planning its network.

As part of internalising its asset management strategy, IT strategy and corporate services functions, United Energy forecasts that the number of employees it directly (or on contract) employs will increase significantly over the next several years. The current JAM contract will expire on 30 June 2011 and the AER noted that the major increase in staff is not expected to occur until 2011. Table I.1 provides a breakdown of services which are provided internally and services which are outsourced under the new business model.

Table I.1 In-house and outsourced functions under United Energy's new business model

Function	In-house includes:	Outsourced includes:
Network management	Development of asset management plans and work programs Network planning Maintenance planning	Operations services Control centre operations
Customer and market management	Business development AIMRO contract management Management of key end users and stakeholders	Customer contact centre services AIMRO program management office
IT services	IT strategy and architecture IT service delivery management	Infrastructure and applications management IT project and management services
Corporate services	Business development Legal and key contract management Regulatory services Finance HR and admin	Not outsourced

Source: United Energy, *Regulatory proposal*, November 2009, pp. 22–23.

4 United Energy, *Initial regulatory proposal, appendix F–3, Project seven 11, Commercial & regulatory strategy, United Energy board paper*, April 2009; United Energy, *Initial regulatory proposal, appendix F–4, AT Kearney, Business model review*, November 2009.

The AER noted in its draft decision that United Energy has almost completed a tendering process for the period after its contract with JAM expires, even though the current contract does not expire until 30 June 2011. The outcomes from the tender process in relation to the unit costs of outsourced services form the basis of part of United Energy's opex forecast in its regulatory proposal.

United Energy considered that it undertook what it describes as a ‘best of breed’ tendering approach, whereby specialist contractors in different areas (for example, construction and IT) were encouraged to form a consortium and bid against competing consortia. United Energy received responses from four consortia who wanted to participate in the final stage of the tender process. The AER noted that United Energy has selected its preferred tenderer and refers to the winning applicant as its ‘turnkey service provider’.[5]

As part of its new business model, United Energy advised that it will be separating its network into two geographical regions (that is, northern and southern regions). The turnkey service provider will manage and operate one of those regions, however, the other region will be awarded to some other party. In addition, the consortium partner will provide customer and market management and IT services for both regions. In ‘phase 1’ of the transformation, the turnkey service provider is responsible for managing all of the contracts including its own and the second regional contract. In ‘phase 2’, it is intended that United Energy will take over management of the second regional contract. Eventually, in ‘phase 3’ United Energy anticipates that it will take over the direct management of all the contracts including those held by the turnkey service provider. United Energy’s proposal appears to assume phase 2 occurs in year three of the forthcoming regulatory control period. However, the AER noted that the timing of phases 2 and 3, and the decision as to whether they even occur, is at the discretion of United Energy and is not prescribed by the new contract with its turnkey service provider.[6]

The AER noted that the current JAM contract includes a clause giving JAM a ‘right to match’ the terms of any future contract. Accordingly, if JAM exercises its right to match then it will become the turnkey service provider and the winning applicant will take the contract for the second regional network. The AER understands that JAM has not yet indicated whether or not it will exercise its right to match. United Energy has advised that JAM and United Energy have been involved in a formal dispute resolution process in relation to JAM's 'right to match' under the OSA. United Energy has subsequently advised that on 29 June 2010 a final determination was made in relation to this dispute and United Energy is now confident that it is not obliged to put an offer to JAM to match under the OSA and is able to pursue its long term commercial objectives.[7]

I.2 Regulatory requirements

As noted at the beginning of the opex chapter (chapter 7), United Energy proposed an allowance for in-house opex costs and outsourced opex as components of their total

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5 United Energy, *Regulatory proposal, appendix F–4*, November 2009.
6 ibid.
7 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 29.

proposed forecast opex for the 2011–15 regulatory control period. The assessment of United Energy's in-house and outsourced opex forecast is relevant to determining whether the AER is satisfied that the total proposed forecast opex or its estimate of the required opex reasonably reflects the opex criteria.

Specifically, this appendix assesses the proposed allowance and what the level of efficient expenditure for total opex which a prudent operator, in the actual circumstances of United Energy, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the opex objectives. This assessment in turn raises issues of whether the opex forecast in relation to United Energy's new business model reasonably reflects the efficient costs and whether these costs reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives given the level of substantiation of these costs. As is discussed further in this appendix, the AER considers that the opex factors, 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(4) and 6.5.6(e)(5) are particularly relevant to this assessment.

I.3 AER draft decision

The AER assessed United Energy's operating and maintenance costs forecast based on the following four components:

- unit costs associated with tendered services
- unit volumes associated with tendered services
- unit cost associated with services provided internally or through related parties
- unit volumes associated with services provided internally or through related parties.[8]

The AER was satisfied that the component of United Energy's opex forecast related to unit costs associated with tendered services (that is, the tendered unit costs) reasonably reflected the opex criteria.[9] These unit costs have been established through a reasonably competitive tender process. However, the AER was not satisfied that the remaining three components reflected the opex criteria, which included the:

- unit volumes associated with tendered services
- unit cost associated with services provided internally or through related parties
- unit volumes associated with services provided internally or through related parties.

8 AER, *Victorian electricity distribution network service providers, Distribution determination 2011–2015*, Draft decision, June 2010, p. 230.
9 ibid., p. 232

The AER concluded that these components of United Energy's opex forecast were not well substantiated in United Energy's proposal or in the subsequent information received by the AER.[10]

In particular, the AER noted that while the unit costs associated with outsourced services have been determined via tender, the unit volumes associated with these services estimated by United Energy were not satisfactorily substantiated. [11] A KPMG report submitted by United Energy stated that United Energy sourced information from JEN and internally to determine the forecast volumes of operating and maintenance work on its network.[12] However, few details were provided on this information and the information itself was not submitted by United Energy with its regulatory proposal. The AER also noted that United Energy did not provide historical volume information with its proposal, nor did United Energy demonstrate how its forecasts were consistent with historical patterns, or why they differed from historical levels if this was the case.

The AER noted that United Energy's internal opex forecasts were constructed at a highly detailed level. For example, the salaries of each individual employee (plus on costs) were forecast over the 2011–15 regulatory control period, and then aggregated. The AER concluded that this high level of specification was not robust due to the significant degree of estimation involved in the forecast that was not sufficiently supported.[13]

The AER summarised its conclusions in table 7.8 of the draft decision which is reproduced below.

Table I.2 AER draft decision—Assessment of different components of United Energy’s opex forecast

Component of forecast	AER assessment
Outsourced services—unit costs	Units costs derived from reasonably competitive tender process. No significant concerns.
Outsourced services—unit volumes	Unit volumes estimated by UED. Not substantiated.
In-housed services—unit costs	Unit costs estimated by UED. Source material provided (through had not previously been referred to in regulatory proposal). No clear link between source material and forecast.

10 United Energy, *Regulatory proposal*, November 2009, p. 232.
11 ibid., p. 231.
12 United Energy, *Regulatory proposal, appendix C–1, KPMG and Johnson Winter & Slattery, United Energy Distribution, Forecasting methodology for operating and capital expenditure,* November 2009, pp. 73–75.
13 AER, *Victorian distribution determination*, Draft decision, June 2010, p. 231.

In-housed services—unit volumes	Unit volumes estimated by UED. Source material provided. Connection between source material and forecast not established.

Source: AER analysis

The AER also noted that United Energy sought to recover the forecast transformational costs associated with the move to its new business model. These transformational costs included the upfront costs of implementing new business processes and systems and meeting the costs of redundancies associated with gaining efficiencies.[14] The AER also considered United Energy's 'reference line' estimate of what it considered opex would have been in the forthcoming regulatory control period if it had remained with its current business model and compared this against the forecast opex in its regulatory proposals. The AER identified several issues with the calculation of United Energy's reference line. These concerns included:

- The 'base year' estimate of the reference line forecast overstated the costs United Energy would incur under the continuation of its current business model due to the inclusion of transformational costs incurred in transitioning to the new business model

- United Energy assumed that a continuation of the current business model would result in an increasing cost profile over the forthcoming regulatory control period. However, the AER considered that the rate of change assumption underlying this forecast may not be realistic given it is based on ESCV estimates for 2006–10

- United Energy assumed that under its current business model it would face a rising cost profile, whereas the winning tender application is expected to face a much lower cost profile. However, United Energy did not provide any information to demonstrate that it is reasonable to assume that JAM and the winning tender applicant would have differing cost profiles.

The AER concluded that given the issues with the calculation of the reference line estimate identified by the AER, and the qualifications on its purpose and usefulness as described by United Energy, the AER was not satisfied that the comparison of the reference line estimate demonstrates that United Energy's opex forecast reasonably reflects the efficient costs that would be incurred by a prudent operator in United Energy's circumstances, or a realistic expectation of input costs.[15]

The AER derived its assessment of United Energy's required opex, adjusted by the minimum amount necessary in accordance with the requirements of the NER, from:

- a 'base year' opex, derived mostly from the historical expenditure incurred in operating United Energy's network under its current business model

14 AER, *Victorian distribution determination*, Draft decision, June 2010, p. 233.
15 ibid., pp. 234–35.

- adjusted for scale, real cost escalation and step changes in the same manner as for the other Victorian DNSPs.[16]

I.4 United Energy revised regulatory proposal

United Energy response to approach to overall opex forecasts

United Energy submitted that the AER must consider the precedent that it has set in other jurisdictions when it examines the efficiency and prudency of United Energy's expenditure forecasts. United Energy stated that the AER's conclusion that United Energy's expenditures are inefficient is inconsistent with the AER's approval of expenditures in other jurisdictions that are up to four times greater on a per customer basis.[17]

United Energy considered that the AER is embarking on a course that will deliver better electricity infrastructure to the New South Wales consumer compared to Victorian consumers. The AER's approach to United Energy's opex forecasts shows that the AER is reluctant to recognise the commercial reality that the pursuit of efficiency gains may require the adoption of new business structures. The AER's draft decision makes projections—not forecasts or estimates of United Energy's opex—based on a false premise that the status quo will continue. United Energy considers that this approach is counter to the NEO and the AER's obligations under the NEL. United Energy submitted that its revised regulatory proposal provided further evidence to demonstrate that it is an efficient cost performer and that United Energy's original proposal compares well with its peers. United Energy referred to a paper by Mountain and Littlechild to support its view.[18]

United Energy stated that the forecast price path comparison between the NSW and Victorian DNSPs illustrated that:

- the price increases originally proposed by United Energy for the forthcoming regulatory control period are modest compared to those approved by the AER in its 2009 NSW determination

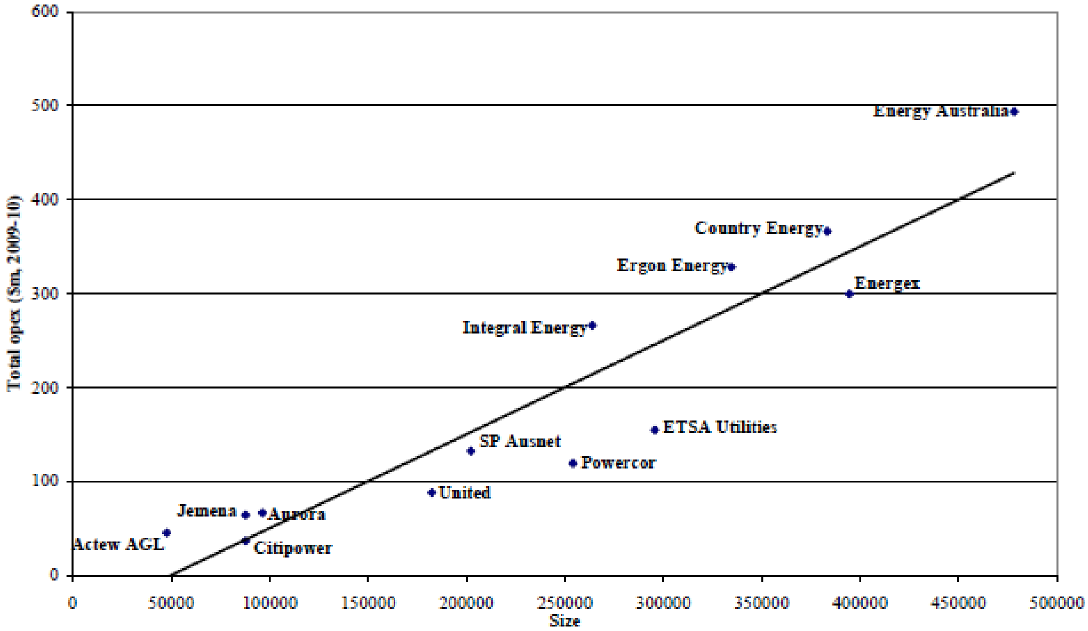
- if United Energy's original proposal were to be accepted , United Energy's prices would be 37 per cent lower than those already approved by the AER for New South Wales

- if the price controls in the draft decision were implemented, United Energy's distribution prices in 2014 would be 60 per cent lower than those approved by the AER in NSW.[19]

United Energy stated that similar conclusions can be drawn in relation to the Queensland DNSPs.[20] United Energy referred to analysis undertaken by the AER for the Queensland DNSPs, reproduced in figure I.1:

[16] AER, *Victorian distribution determination*, Draft decision, June 2010, pp. 235–36.
[17] United Energy, *Revised regulatory proposal*, July 2010, p. xvi.
[18] ibid., p. xvii.
[19] ibid., p. xix.
[20] ibid.

Figure I.1 Comparative analysis of opex versus size for Australian DNSPs ($'m, 2009–10)



Source: AER analysis

United Energy stated that the AER's regression analysis showed that United Energy's opex is approximately 30 per cent lower than the efficient opex predicted by the AER's analysis.[21]

Frontier Economics (engaged by United Energy) commented that the AER's findings in its draft decision on Queensland DNSPs appeared to be too limited to develop firm conclusions, although they do show United Energy to be significantly more efficient than most DNSPs in the NEM.[22] United Energy also referred to comments by Frontier Economics, that per customer number revenues of the Victorian DNSPs appeared to be significantly lower than in NSW, and this seemed to be in part due to the result of lower opex per customer by Victorian DNSPs.[23]

United Energy provided a comparison of the AER's opex allowances for the NSW and Queensland DNSP as further evidence that the AER's rejection of its opex forecast is odd.[24]

United Energy submitted that this analysis indicated that the AER's draft decision for United Energy is inconsistent with the outcomes of the AER's determinations in other jurisdictions. United Energy expressed concerns given the similarities in the broad circumstances of all Australian DNSPs in terms of:

- the sustained upward pressure on labour and contract costs in the context of an on-going resources boom and national markets for labour and materials

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21 United Energy, *Revised regulatory proposal*, July 2010, p. xix.
22 ibid., p. xx.
23 ibid.
24 ibid.

- the need to increase investment and maintenance as the electricity distribution infrastructure installed across Australia in the post-war era ages and approaches the end of its serviceable life

- the need to meet increasing peak demand and to connect new customers in a national economy that has exhibited sustained growth over the past decade

- the need to comply with common health, safety, environmental and technical regulatory obligations

- the additional investment and opex required to address issues relating to climate change.[25]

United Energy considered that this analysis demonstrated that the AER has adopted an inconsistent approach in its application of the NER in the Victorian draft decision, compared to its approach in its recent Queensland and NSW determinations.

United Energy submitted that it is concerned that the AER's conclusions regarding United Energy's reference line calculation are based on the AER's misunderstanding or mischaracterisation of the purpose of the reference line. United Energy reiterated that the reference line comparison provided a 'stress test' for United Energy's forecasts, and in this sense it is useful in terms of validating the reasonableness of United Energy's opex forecasts for the forthcoming regulatory control period.[26]

In response to the draft decision, United Energy stated that:

- The new business model necessitates a ‘bottom up’ forecasting approach, rather than a ‘year 4’ approach as adopted by the AER’s draft decision. United Energy stated that a ‘year 4’ approach does not represent a valid forecast and as such United Energy would be breaching the Rules if it developed a forecast of its opex in that way.

- The AER’s ‘year 4’ approach can be used to ‘stress test’ United Energy’s forecasts for its new business model, similar to United Energy’s reference line approach. However, the application of the AER’s approach for United Energy contains a number of inappropriate adjustments and escalation factors.

- United Energy has provided a detailed explanation of the amendments that should be made to the AER’s ‘year 4’ approach in order for it to provide a reasonable ‘stress test’ for United Energy’s opex forecasts. This amended calculation illustrates that United Energy’s original opex forecast for its new business model is reasonable and should be accepted by the AER.

- United Energy considers that the AER has established clear precedents by adopting opex forecasts in its NSW and Queensland determinations. The AER must consider the precedent that it has set in other jurisdictions when it examines the efficiency and prudency of United Energy’s forecasts.

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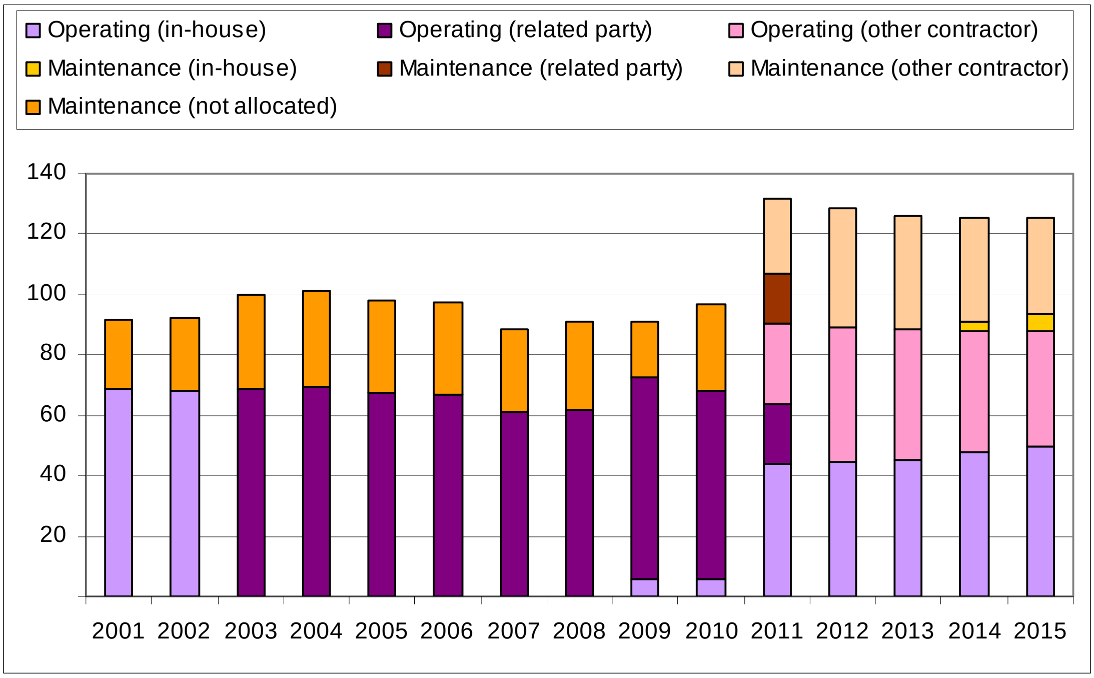
25 United Energy, *Revised regulatory proposal*, July 2010, p. xxi.
26 ibid., p. 27.

- United Energy has fully substantiated its opex forecast in accordance with the requirements of the Rules and in accordance with those requirements the AER must accept United Energy's forecast opex for the forthcoming regulatory control period.[27]

United Energy also stated that it did not agree with the AER's draft decision to reject the remaining components—namely outsourced work volumes, in-house volumes and in-house unit costs. United Energy's historical and forecast opex is outlined in figure I.2.

Figure I.2 United Energy revised proposal—Historical, estimated and forecast operating and maintenance expenditure ($'m, 2010)



Source: United Energy revised proposal RIN templates

I.5 Submissions

The EUCV agreed that the AER's argument for not allowing United Energy's approach to be incorporated in the opex element of the allowed tariffs for the new regulatory control period is strong and cogent. The EUCV also stated that the AER did not address that United Energy is permitted to expend its opex in any way it sees fit, only that the efficient and prudent opex will be allowed into the tariffs. The EUCV stated further that if United Energy considers that its new approach will result in savings, then:

- it can make the decision to implement the new approach
- under the EBSS, United Energy will be able to retain the benefit of the savings it generates in this and the forthcoming regulatory control period.[28]

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27 United Energy, *Revised regulatory proposal*, June 2010, pp. 37–38.

28 EUCV, *2010 AER review of Victorian Electricity DBs: EUCV response to AER Draft Decision*, August 2010, pp. 34–35.

The EUCV also submitted that it supports the principle that a distribution business has the freedom to initiate approaches to improve long term efficiency, and as a result, the EUCV accepts that a distribution business (United Energy in this case) should be rewarded if its initiative results in a more efficient outcome. The EUCV considered that what the AER has implied in its draft decision is that United Energy can develop its opex approach in any way it wants to, but the AER will not allow United Energy to increase tariffs as a result of the new approach.[29]

I.6 Issues and AER considerations—New business model O&M forecast

The AER concluded in its draft decision that it was not satisfied that United Energy's total forecast opex reasonably reflected efficient and prudent costs in the circumstances of United Energy. The AER formed this view on the basis that elements of United Energy's total opex forecast were not substantiated or justified in terms of why these costs differ from historical patterns. In reviewing United Energy's forecast opex, the AER had regard to the costs incurred by United Energy under its current business model where significant emphasis was placed on 6.5.6(e)(5) of the NER. The AER also noted that in placing significant emphasis on United Energy's current business model costs, the AER had regard to benchmarking analysis (consistent with clause 6.5.6(e)(4) of the NER).

The AER does not consider that United Energy's reference to comparing the pricing outcomes in NSW with United Energy's proposals, or the AER's draft decision, is a relevant consideration under the NER. The AER notes that the pricing outcomes for the Victorian and NSW DNSPs reflect the outcomes of the AER's constituent decisions for the relevant building block components for the respective DNSPs. The AER for example, notes that transitional provisions in the NER applied to the NSW DNSPs in relation to the cost of capital.

Further, the AER does not accept United Energy's assertion that it has been inconsistent with previous AER decisions on the basis that it has approved higher opex allowances as evidenced by opex per customer. The AER is not satisfied that the analysis provided by United Energy demonstrated that the AER has approved inefficient expenditure for DNSPs in other jurisdictions. In comparing the outcomes of previous determinations the AER notes that there are a number of reasons, other than inefficiency, for differences in cost ratios such as opex per customer. In particular, the AER notes that opex allowances may vary between DNSPs based on differences in:

- customer geographic density (it is likely to be cheaper to serve customers which are geographically dense with shorter, larger lines than customers which are geographically scattered)
- customer demand characteristics (low capacity factors would be expected to imply higher cost per customer)

[29] EUCV, *2010 AER review of Victorian Electricity DBs: EUCV response to AER Draft Decision*, August 2010, p. 36.

- peak demand (higher demands is likely to require greater investment in the network)

- the number of customers (if there are economies of scale, larger businesses will have lower average costs)

- the definition of distribution services (if higher voltage services are included within distribution services it is likely to lead to a higher cost per customer)

- the range of services provided (distribution businesses may differ, for example, in the role they play in installing and reading meters)

- in the quality of the services provided (such as the number of faults, and the time to repair faults)

- in the weather (harsher conditions may require more investment in network assets);

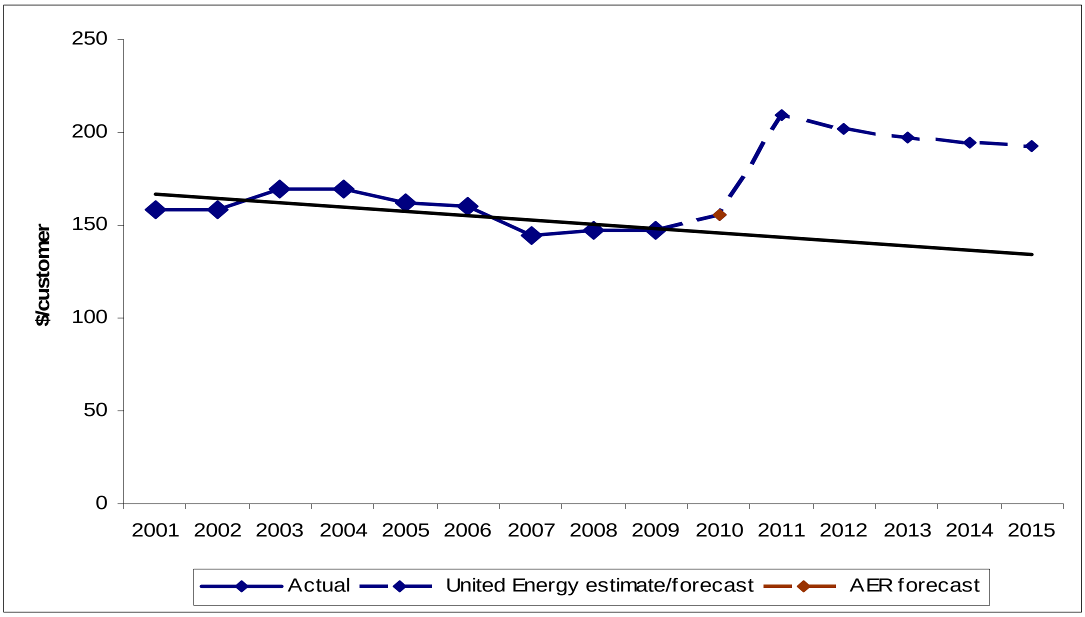
- in the degree of undergrounding required; differences in the cost of that undergrounding (for example, different costs of tunnelling and burying cable).

- in the rate of growth of the network

- other factors such as differences in the mobility of customers.

The AER also notes, as shown in figure I.3, that while opex per customer suggests that United Energy is relatively efficient, United Energy has projected that opex per customer will deteriorate significantly over the forthcoming regulatory period. Accordingly, the AER advocates a cautious approach in comparing the performance of DNSPs on the basis of simple partial indicators, especially on the basis of simple ratios.

Figure I.3 United Energy opex per customer ($'m, 2010)



Source: AER analysis

The AER also notes that Frontier Economics, engaged by United Energy for its revised regulatory proposal, commented that:

> In my view, the AER's benchmarking analysis in Appendix I of its Draft Decision and noted above does not go far enough to allow the AER to properly assess whether UED's forecast operating expenditure is efficient. The AER itself concedes that the data used in its analysis has to be corrected for differences in regulatory environment, asset classifications, network maturity and geographical factors. In addition, the AER's findings in its draft decision on the Queensland DNSPs also appear to be limited to come to firm conclusions, although they do show UED to be significantly more efficient than most DNSPs in the NEM.[30]

The AER agrees with Frontier Economics, that the AER's benchmarking analysis cannot be relied upon to assess the efficient and prudent costs of the DNSPs' opex over the forthcoming regulatory control period. The AER, in applying its regression analysis to the Queensland DNSPs, also noted the limitations of this benchmarking analysis in terms of the:

- size of the data set
- discrepancies in opex definitions
- differing regulatory arrangements.[31]

The AER also recognised in this draft determination that while benchmarking is a useful analytical tool, its use should be limited to top down testing of a more detailed bottom up assessment, informed by due consideration of the opex factors.[32] Consistent with the AER's previous views regarding the application of benchmarking, the AER considers that at the current time, as discussed in appendix I, it cannot establish revenue allowances based primarily on the outcome of comparative benchmarking against other businesses. The AER also considers, as discussed in appendix I, that when a more standardised approach and appropriate data becomes available and benchmarking tools give more consistent results, the emphasis given to top down benchmarking as part of the AER's assessment may be more significant. For the reasons identified above, the AER considers that while high level benchmarking is a useful tool in assessing a DNSP's opex forecast, benchmarking comparisons for this review cannot be relied upon to assess whether United Energy's forecast opex reasonably reflects efficient and prudent costs.

In response to United Energy's claim that the AER has been inconsistent with its approach in other jurisdictions—based on the similarities between the operating environment of all Australian DNSPs—the AER notes that, as was the case in previous determinations, United Energy's forecast opex in the draft decision and this final decision reflects the expected changes in real input costs over the forthcoming

30 Frontier Economics, *Meaning and application of National Electricity Rule 6.5.6(c)*, a report prepared for Johnson Winter & Slattery, July 2010, p.15.

31 AER, *Queensland, Draft distribution determination 2010-11 to 2014-2015*, 25 November 2009, appendix I, p. 625.

32 ibid., p. 625

regulatory control period. These considerations are discussed in greater detail in appendix K.

The AER has also approved a substantial increase in United Energy's renewal and augmentation capex, but does not consider that additional opex is required for the ageing assets for the Victorian DNSPs. The AER has however, provided United Energy with an allowance for increased opex over the forthcoming regulatory control period related to servicing a larger network. These considerations are discussed in greater detail in appendix J.

Further, the AER has provided United Energy with additional opex over the forthcoming regulatory period for costs arising from expected changes in United Energy's operating environment (including changes in regulatory obligations). The AER, however, does not expect that the Victorian DNSPs will incur substantial cost increases due to climate change, as these costs impacts are already reflected in the DNSPs base year and any expected costs are expected to be gradual over time. These considerations are discussed in greater detail in appendix L.

In response to the AER's draft decision, the AER also notes that United Energy engaged KPMG to explain how its original report (prepared for United Energy's initial regulatory proposal):

- provided evidence that supported the assumptions underpinning United Energy's opex forecasts
- demonstrated that United Energy's forecasts are consistent with the NER.[33]

United Energy considered that its revised regulatory proposal, including the KPMG report, fully substantiated its opex forecast in accordance with the requirements of the NER.[34]

KPMG summarised the evidence that it considered supported the assumptions of unit costs and volumes on which United Energy's opex forecasts are based. In reference to United Energy's opex forecasts, KPMG stated that it found that:

- the prudency and realism of the volumes of capex and opex are evidenced by independent advice from AECOM and Deloitte, benchmarks of actual volumes of activity experienced in the current regulatory control period and the competitive tendering process
- United Energy's forecasting methodology forecasts efficient expenditure on the basis of input costs derived from benchmarks and market based evidence, and costs that are consistent with the 2006 EDPR
- United Energy's methodology for forecasting capex and opex for the 2011 EDPR is based almost entirely on assumptions that have a transparent supporting rationale.[35]

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[33] KPMG, *Bases of forecasts of operating expenditure*, July 2010, p. 3.
[34] United Energy, *Revised regulatory proposal*, p. 38.
[35] KPMG, *Bases of forecasts of operating expenditure*, July 2010, pp. 5–6.

The AER considers, however, that the analysis provided by KPMG does not sufficiently demonstrate that United Energy's opex forecasts reasonably reflect the opex criteria. In particular, the AER considers that the KPMG report did not provide an opinion or assessment of United Energy's forecasts against the requirements of the NER.[36] Rather, the AER considers that the KPMG report merely concluded that United Energy implemented its forecasting methodology in a manner consistent with its design.[37]

Further, the AER notes that as stated in KPMG's initial report on United Energy's forecasting methodology, KPMG did not provide an opinion, nor were they tasked with providing an opinion, as to the prudency or efficiency of United Energy's opex forecasts:

> In accordance with our terms of reference, we [KPMG] do not opine on the efficiency and prudence of UED's expenditure forecasts or on the achievability of those forecasts.[38]

KPMG also stated that in reaching the draft decision the AER has neither explained the substantiation for future events that it reasonably expects of United Energy, nor why it believes that the assumptions that underpin United Energy's opex forecasts are unreasonable. In response, the AER notes that the draft decision set out its reasoning, where the AER was not satisfied that United Energy's forecast opex reasonably reflected the opex criteria, on the basis that:

- few details were provided related to volumes associated with outsourced services
- United Energy had not provided historical volume information nor demonstrated how its forecasts are consistent with historical patterns or
- why they differ form historical levels if this is the case.[39]

KPMG further stated that:

> In particular it is not clear to us where the aptness of a forecasting assumption is supported by information sourced internally by UED or from a related party that this suggests that the supporting information is necessarily of lesser relevance or quality. Generally one would expect that most relevant or specific bases of information for forecasting assumptions and judgements would be sourced from within the entity making the forecast. Evidence from other parties such as benchmarks (which UED has

36 The AER acknowledges that appendix J, included in KPMG's initial report, summarises the checks carried out by KPMG on United Energy's internal costs assumptions. This appendix purports to have agreed the basis and amount to the source documentation of United Energy's forecasts. The AER, however, notes that no analysis or assessment of the reasonableness of United Energy's opex forecasting assumptions is evident. KPMG, *Forecasting methodology for operating and maintenance expenditure, appendix J*, November 2009, pp. 142–146.

37 KPMG, *Forecasting methodology for operating and maintenance expenditure*, November 2009, p. 11.

38 ibid., p. 11.

39 AER, *Draft decision*, June 2010, p. 231.

> employed) may help by corroborating such sources, but they do not substitute for them.[40]

The AER agrees with KPMG that relevant information for forecasting in many instances would be sourced from within the entity making the forecast. The AER notes however, that in a regulatory context the AER is required to be satisfied that any ex ante forecasts reasonably reflect prudent and efficient costs. In order to do this the AER assesses the information provided by the DNSPs in relation to its forecasts. The AER has placed significant emphasis on United Energy's existing costs under its current business model to assess its forecast opex under its new business model. In particular, the AER has concerns that United Energy's total forecast opex under its new business model is significantly higher than its existing costs incurred under its existing business model (as shown in figure I.2).

KPMG also stated that it estimated that three per cent of United Energy's total forecast opex is supported solely by management experience based on judgements.[41] The AER's review of United Energy's regulatory proposal does not support this statement. In particular, the AER notes that a substantial proportion of outsourced unit volumes are based on modifications by United Energy to JAM's planned volumes for these services. The AER's consideration of this issue is provided in section I.6.2.

In relation to benchmarks and market based evidence, the AER recognises that benchmarking is a relevant opex factor in considering the opex criteria. The AER has some reservations in this final decision regarding this benchmarking on the basis that:

- cost categories that have been subject to benchmarking are estimated by United Energy to increase substantially over the forthcoming regulatory control period
- the KPMG benchmarking reports appear to have been based on analysis that is over 10 years old
- KPMG has explicitly stated that it does not draw any conclusions from this analysis as to the efficiency of United Energy's costs.[42]

The AER notes that benchmarking of some of these activities are related to 'other operating expenditure' which is estimated to increase substantially over the forthcoming regulatory control period (that is, in the order of 43 per cent).[43] The AER considers that United Energy has not explained why this forecast opex category is expected to increase substantially (above existing levels) over the forthcoming regulatory control period.

40 KPMG, *Forecasting methodology for operating and maintenance expenditure*, November 2009, p. 2.

41 KPMG, *Forecasting methodology for operating and maintenance expenditure*, November 2009, p. 6.

42 The AER notes that it is not clear as to the magnitude of United Energy's forecast opex that has been subject to benchmarking analysis. In particular, the AER notes that KPMG benchmarked $192m ($2010) of United Energy's non-network expenditure for the forthcoming regulatory control period, which covered corporate costs, customer market management and IT expenditure. However, KPMG has stated elsewhere that only $47-49m ($2010) of forecast expenditure under the new business model has been subject to benchmarking.

43 United Energy, *Revised regulatory proposal*, RIN template 3.1.

The AER also notes that the benchmarking information appears to relate to the 2000 distribution reset, which suggests that the information utilised in these benchmarking studies may be out of date. Further, these benchmarking studies were used to establish the ORG's forecast opex allowance for the 2001–05 regulatory period. United Energy made efficiency savings over this period such that any reliance on these benchmarks to inform United Energy's forecast opex would include past efficiencies that should not be retained by United Energy.

A review of some of the categories benchmarked by KPMG revealed that KPMG has benchmarked costs that the AER has identified as being double counted in United Energy's forecast opex, for example, United Energy's financial services agreement costs with AMPCI.

Finally, the AER notes that KPMG stated that:

> We emphasise that our benchmarking comparison at Appendix K is not intended to draw conclusions on the efficiency of UED's operating expenditure forecasts. This is not within our terms of reference.[44]

United Energy also engaged AT Kearney to submit a report analysing United Energy's opex forecasts and to provide the AER with further supporting arguments in relation to[45]:

- forecast unit volumes associated with tendered services
- unit volumes associated with services provided internally
- forecasts of unit costs associated with services provided internally.[46]

The AER notes that the AT Kearney report did provide additional analysis to that already provided by KPMG or United Energy, in relation to United Energy's in-house, non-labour costs. In particular, the AT Kearney report provided greater granularity as to the derivation of United Energy's in-house, non-labour opex forecasts.[47] However, the AT Kearney report did not provide additional information or analysis with respect to United Energy's unit volumes associated with tendered services, or United Energy's forecast in-house labour volumes and labour unit costs.

Further, similar to the KPMG report, the AER considers that AT Kearney did not assess the reasonableness of the assumptions underpinning United Energy's forecasts in relation to in-house, non-labour forecasts. Moreover, the AT Kearney report consistently relied upon conclusions drawn from the KPMG report, of which the AER has expressed concerns. As such, the AER considers the AT Kearney report to be of modest value in assessing whether United Energy's opex forecasts over the forthcoming regulatory control period reasonably reflect the opex criteria.

44 KPMG, *Forecasting methodology for operating and maintenance expenditure*, November 2009, p. 90.
45 United Energy, *Revised regulatory proposal*, p. 55.
46 United Energy, *Revised regulatory proposal*, Appendix C-4, p. 2.
47 ibid., pp. 33–34.

In reviewing United Energy's revised regulatory proposal and supporting information, the AER has reassessed United Energy's forecast:

- volumes associated with outsourced services
- unit costs associated with in-house services
- unit volumes associated with in-house services.

The AER's consideration of these issues is discussed below.

I.6.2 Outsourced work volumes

I.6.2.1 AER draft decision

The AER noted that United Energy did not provide historical volume information with its proposal nor demonstrate either how its forecasts were consistent with historical patterns, or why they differed from historical levels if this is the case. The AER considered that the forecast volumes associated with outsourced activities had not been substantiated in United Energy's regulatory proposal.[48]

I.6.2.2 Victorian DNSP revised regulatory proposals

Bidders submitted budgets based on prices and volumes combined

United Energy submitted that the distinction drawn by the AER between the tender price and volumes was invalid in this case because the tender process determined unit prices and volumes concurrently, and the 'price' offered by each tenderer was in the form of an operating expenditure budget that reflected the product of unit prices and forecast volumes.[49]

United Energy also argued that there was a strong incentive on United Energy and each tenderer to ensure that bids were based on the best possible information regarding expected unit prices and work volumes, on the basis that:

- a tenderer must submit the lowest five-year opex budget to be successful
- the budget will determine United Energy's operating expenditure allowance, and therefore United Energy will have a very limited capacity to fund costs above the tendered budget.[50]

United Energy submitted that the contract priced by tenderer's for the purpose of the regulatory proposal placed the contractor's entire gross margin at risk depending on cost efficiency and service quality, therefore its conditions of tender made it clear that tenderer's should inform themselves and not rely on United Energy representations in constructing their binding offers.[51]

United Energy also provided a letter from its probity auditor Dench McClean Carlson Corporate Advisory ("DMC") to provide probity advice in respect of the process for

48 AER, *Vic Draft decision*, June 2010, p. 231.
49 United Energy, *Revised* r*egulatory proposal*, July 2010, p. 48.
50 ibid.
51 United Energy, *Revised* r*egulatory proposal*, July 2010, pp. 49–50.

the procurement of Utility Operations and Management Services, which concluded that:

> From the examination of the documents we would conclude that the bidders developed their pricing using volumes which they assessed as commercially feasible - either accepting the volumes proposed in the RFP or providing their own.[52]

Volume plays a limited role in determining operating expenditure forecasts

United Energy submitted that volumes played a relatively limited role in determining operating expenditure forecasts because prices provided by tenderer's fall into two categories:

- line items comprising a 'unitised' price multiplied by a planned volume representing repetitive work elements
- line items comprising services which by their nature can only be sensibly stated as a single annual unit of service (i.e. volume of 1).[53]

United Energy contended that only 31.1 per cent of the outsourced five-year opex budget obtained through the tendering process falls into the first category, and the impact of forecast unit volume information error on forecast opex would be significantly diluted.[54]

Forecast outsourced unit volumes are closely linked to actual historical volumes

United Energy submitted that its forecast volumes of operating and maintenance work were based on actual 2009 work volumes supplied by JAM.[55] In addition, United Energy stated that as a starting point for the development of tendered operating expenditure budgets, United Energy supplied tenderers' with JAM's planned 2009 work volumes for operating and maintenance work with minor modifications in two areas only:

- adjustments to reflect expected impact of changes in the Asset Management Plan (AMP) anticipated for the 2011–15 period to reflect United Energy's latest understanding of asset condition and risks
- adjustments in expected volume of fault response work in line with United Energy's analysis of climate trends. In this context, United Energy noted that the tenderers' provision for fault response amounts to 5.2 per cent of the tendered opex budget.[56]

United Energy submitted that AECOM has reviewed these adjustments and noted that overall changes from 2009 volumes were neither material nor unreasonable.[57] United Energy also contended that these United Energy-supplied work volumes were not directly relevant to the operating expenditure forecasts, as those forecasts were based

52 ibid., p. 50.
53 ibid., p. 51.
54 ibid.
55 ibid.
56 United Energy, *Revised regulatory proposal*, July 2010, p. 51.
57 ibid., pp. 51–52.

on the tenderers' tendered proposals, however they can be employed to compare forecast unit volumes to historic volumes.[58]

Details of forecast outsourced unit volumes compared to historic volumes

United Energy submitted that AECOM confirmed that United Energy provided bidders with 'year 4' 2009 volumes for outsourced services in response to the AER's concern regarding the absence of detailed information in the initial regulatory proposal in relation to:

- forecast volumes of operating and maintenance work
- historic volume information
- information on consistency with historical patterns or reasons for any differences.[59]

In addition, United Energy submitted that it has provided in its revised proposal a detailed comparison of current and forecast unit volumes which demonstrated that forecast volumes were substantially the same as existing volumes, as noted by AECOM in its independent expert report.[60]

I.6.2.3 Issues and AER considerations

The AER's assessment of United Energy's proposed unit volumes associated with the tendered services is set out below.

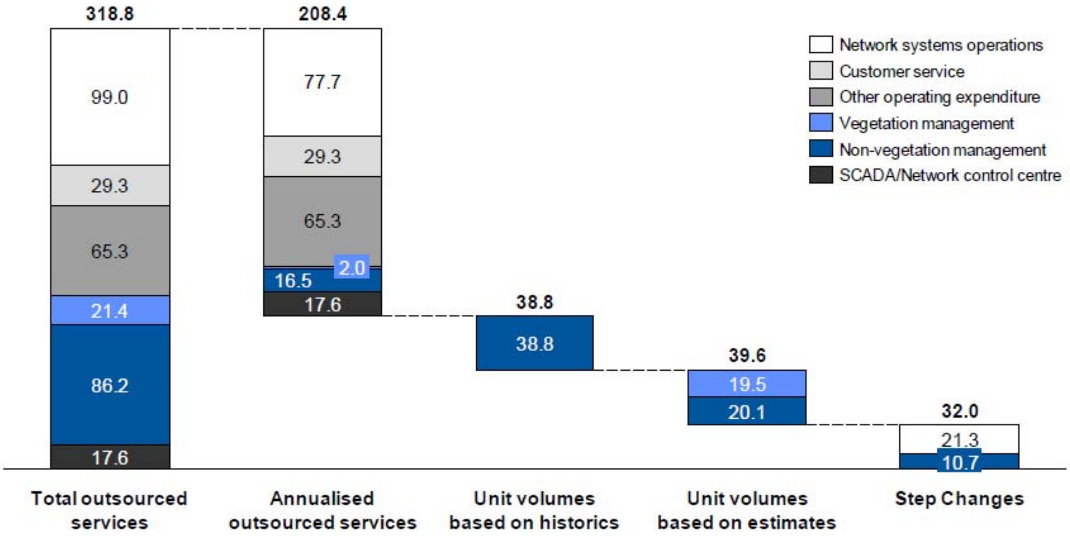
The AER notes that based on the further report provided by United Energy's advisor AT Kearney has grouped total outsourced forecasts include four categories:

- outsourced service line items comprising services which by their nature can only be sensibly stated as a single annual service package
- outsourced services comprising a 'unitised' price multiplied by a planned volume based on historic data
- outsourced services comprising a 'unitised' price multiplied by a planned volume based on volume forecasts estimated by United Energy management and external consultants
- step changes comprising of increased operating and maintenance costs relating to network systems operations, emergency management and routine maintenance.[61]

These categories and the proportion of costs set out in the further AT Kearney report are set out in figure I.4.

58 ibid., p. 52.
59 ibid., p. 52.
60 ibid., p. 52.
61 United Energy, *Revised regulatory proposal*, Appendix 4, Advice on the optimal design of UED's business model, AT Kearney, July 2010, p. 5.

Figure I.4 Outsourced operating and maintenance forecast ($'m, 2010)



Source: United Energy, *Revised regulatory proposal*, Appendix 4, Advice on the optimal design of UED’s business model, AT Kearney, July 2010, p. 6.

The AER notes that United Energy has identified 'annual service line items', where there is no distinction between unit price and volume such that these outsourced services that are the product of price and volume.[62] The AER as stated in the draft decision considers that United Energy conducted a reasonably competitive tender process. As a result the unit costs for outsourced services arising from this tender are likely to reasonably reflect efficient costs. Accordingly, the AER also considers that the budgeted costs for services with an annualised volume of one are likely to reasonably reflect efficient costs and prudent costs in the circumstances of United Energy and realistic cost inputs.

The AER has considered United Energy's step change costs in chapter 7 of this final decision.

The AER has concerns in relation to approximately 28 per cent of outsourced costs (excluding step changes) are related to unit volumes, which is consistent with United Energy's view that 31 per cent of the outsourced five year opex budget obtained through the tendering process is related to unit volumes.[63] This represents $78.4m of United Energy's forecast opex under its new business model.[64] The AER's analysis is focussed on these remaining costs from figure I.4. These include:

- unit volumes based on historical information and
- unit volumes based on estimates.[65]

62 ibid., p. 6
63 United Energy, *Revised* regulatory *proposal*, July 2010, p. 51.
64 United Energy, *Revised* regulatory *proposal*, Appendix 4, Advice on the optimal design of UED’s business model, AT Kearney, July 2010, p. 6.
65 ibid.

Bidders submitted budgets based on prices and volumes combined

In assessing United Energy's outsourced opex forecast based on unit volumes, the AER has reviewed the tender process and contractual arrangements. United Energy stated that there was a strong incentive on United Energy and tenderers' to ensure that bids were based on the best possible information regarding expected unit prices and work volumes.[66] United Energy also stated that conditions of tender made it clear that tenderers' should inform themselves and not rely on United Energy representations in constructing their binding offers.[67]

In response, the AER notes that the tender documentation indicates that the price offered by each bidder was in the form of an operating expenditure budget that reflected the product of unit prices and forecast volumes and the tender process considered unit prices and volumes concurrently. However, the AER notes that United Energy:

- provided forecast volumes to the tenderers which is the basis for United Energy's forecast opex for the forthcoming regulatory control period and
- there is an incentive under the regulatory regime for United Energy to provide the tenderers with higher forecast volumes than necessary to service the network as part of the tender process on the assumption that the Regulator will approve these volumes.

Forecast volumes used to set United Energy's opex forecast

First, the AER notes that United Energy provided the tenderers with forecast volumes associated with the outsourced services. United Energy stated that:

> The RFP (Request for Proposal from United Energy) provided thirteen pages of indicative volumes and metrics (mostly based on historic data) for bidders to consider in developing their competitive bids (pages 126-139).[68]

The AER notes that United Energy's initial and revised proposals have established that for the majority of network operating and maintenance activities, volumes were forecasted and provided by United Energy to the bidders. This is also supported by the AT Kearney report which identifies volume information that was provided by the current service provider and United Energy.[69]

The AER has also reviewed the successful bidder's Total Cost Establishment (TCE) model, which was provided by United Energy in response to the AER's request.[70] The AER notes that the TCE cost is used to forecast United Energy's outsourced opex for the 2011–15 regulatory control period. As stated by United Energy:

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66 United Energy, *Revised* r*egulatory proposal*, July 2010, p. 48.

67 ibid., p. 50.

68 ibid., p. 50.

69 United Energy, *Revised* r*egulatory proposal*, Appendix 4, Advice on the optimal design of UED’s business model, AT Kearney, July 2010, p. 10.

70 United Energy*, email from Schille, A. to Sandles, S. of AER on Questions 2 email dated - TCE Bid - [***word removed CIC***]*, 24 February 2010.

> This data then formed the inputs to the models that calculated the total costs for each outsourced service package for each respondent.'[71]

KPMG also reaffirmed that the costs from the tendering process fed into the opex forecasts for the 2011–15 regulatory control period.[72]

United Energy has also previously confirmed that the TCE model outputs are used to forecast United Energy's outsourced opex for the forthcoming regulatory control period.[73]

That said, United Energy stated that it was the responsibility of the bidders to inform themselves and not to rely on United Energy representations in constructing their binding offers.[74] Dench Mclean and Carlson also stated that:

> The RFP also clearly stated that bidders were responsible for making their own assessments of the information provided in the RFP (pages 42-43).[75]

KPMG commented that:

> UED and Jemena are likely to be in a more informed position than other parties that are not involved with UED's network, to judge what UED needs to do in future to deliver its network services.[76]

Accordingly, the AER does not consider that it necessarily follows that as the bidders were provided with an opportunity to substitute their volumes for the United Energy volumes that this supports United Energy's view that its proposed forecast volumes have been market tested.[77] The AER has examined the contractual arrangements and also agrees with United Energy that the budget (that is, the product of unit price and volume) arising from the tender process will determine United Energy’s operating expenditure allowance, and therefore United Energy will have a very limited capacity to fund costs above the tendered budget. This means that United Energy would have an incentive to propose conservative or volumes that are higher than necessary to service the network to the bidders. The AER's further examination of the incentives under these contractual arrangements is considered further below.

Incentives under the conditions of tender

United Energy stated that the contract priced by the bidders for the purposes of the regulatory proposal places the contractor's entire gross margin at risk depending on cost efficiency and service quality. United Energy also stated that:

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71 United Energy, *Initial regulatory proposal*, November 2009, p. 55.

72 United Energy, *Initial regulatory proposal—Appendix C1 ('KPMG and Johnson Winter & Slattery, United Energy Distribution—Forecasting methodology for operating and capital expenditure, November 2009')*, pp. 32–35.

73 AER, *Email from Sandles, S. to Schille, A. of United Energy on Information requestion - Opex models and other materials*, 5 February 2010; United Energy, *Email from Schille, A. to Sandles, S. of AER on Questions 2 email dated - TCE Bid - [***word removed CIC***]*, 24 February 2010.

74 United Energy, *Revised* regulatory *proposal*, July 2010, p. 50.

75 ibid.

76 United Energy, *Revised* regulatory *proposal*, Appendix C-13, July 2010, p. 8.

77 The AER further notes, United Energy has provided one example that the tenderers' requested a change to the United Energy volumetric data, as noted in Dench McClean Carlson's report.

- the contractor bears 50 per cent of costs incurred above the annual target cost over the regulatory control period, which is largely a function of the tendered budget and

- regardless of the method of its construction, the tendered budget operates as a fixed dollar value for the purposes of determining the contractor's share of any cost over-runs.[78]

United Energy further stated that there is no relief for the contractor if future unit costs or volumes differ from those used to construct the tendered budget, for example if unit costs rise or additional opex is required to achieve the performance targets. United Energy submitted that the tenderers' were explicitly aware of this arrangement when pricing their proposals.[79]

The AER has reviewed the conditions of tender under United Energy's Operational and Management Services Agreement (OMSA).[80] The OMSA provides that the service provider will be paid via a 'three-limb' compensation model with three components as follows:

- reimbursable costs (limb 1) - reimburses actual costs incurred as a result of or incidental to performing services

- contribution fee (limb 2) - represents payment of a contribution margin towards the service provider's profit and corporate overheads, as per the tendered margin

- performance payment (limb 3) - represents the payment of an incentive sum, which may be positive (as a result of good performance) or negative (as a result of poor performance).[81]

The OMSA also indicates that Actual Outturn Cost (AOC) includes the sum of limb 1 and limb 2.[82] The performance payments (limb 3) will be determined for each operational year depending on outcomes in the following two performance areas:

- financial performance, measured by comparing Actual Outturn Cost (AOC) to Target Outturn Cost (TOC)

- non–financial performance, measured by comparing various non-financial outcomes against targets.[83]

Under the OSMA the TOC is a function of ex post earned opex budget (referred to as the EOB) in performing the services and the fixed ex ante budgeted costs from the

78 United Energy, *Revised* r*egulatory proposal*, July 2010, pp. 49–50.
79 ibid., pp. 48–50.
80 United Energy, *Initial* r*egulatory proposal*, Appendix F-2 Operational and Management Services Agreement, Schedule 4 - Budgets and Charges, Mallesons Stephen Jaques, November 2009, pp. 167-68.
81 ibid.
82 ibid., pp. 168–69.
83 ibid., p. 174.

tender process (referred to as the OOB).[84] In addition, the OSAM applies the following performance weightings as provided in table I.3.[85]

Table I.3 Operational performance weightings

Operational Year	**1**	**2**	**3**	**4**	**5**	**6on**
Weight$_{OOB}$	80%	70%	60%	50%	40%	0%
Weight$_{EOB}$	20%	30%	40%	50%	60%	100%

Source: United Energy, *Revised regulatory proposal*, July 2010, p. 49.

Under the OMSA, the financial performance component of the limb 3 will be determined for each year of the forthcoming regulatory control period as provided in table I.4.

Table I.4 Allocation of cost over/under-runs between United Energy and service provider

[Table removed CIC]

Under this contractual arrangement the AER notes the following:

- the target out turn cost is a function of the tender process budget which is fixed for each year of the forthcoming regulatory control period (the TOC is also a function of actual costs)

84 ibid., pp. 180–82. Under the OMSA, the TOC is calculated in accordance with the following formula:

[Formula removed CIC]

85 ibid., pp. 168–69. Original Opex Budget (OOB) is a binding 5-year OOB developed by the Service Provider through the competitive Target Cost Establishment process; WeightEOB = the percentage amount for the applicable operational year; WeightOOB = the percentage amount for the applicable operational year.

- the proportion of the target out-turn costs that is a function of the tender process budget is significant (but declines over the forthcoming regulatory control period relative to actual costs)

- both United Energy and the service provider share in any cost over-runs and under-runs

The AER considers that based on these contractual arrangements there is a clear incentive for United Energy to provide a conservative forecast of outsourced volumes to the bidders as part of the tender process.[86] The AER notes that as the TOC is based on unit prices and unit volumes determined by the tender process to the extent that forecast volumes are conservative, the TOC will be higher than necessary. As a result, where the TOC is higher than necessary, the probability that there will be a cost overrun that is shared between United Energy and the service provider is reduced and a cost underrun is increased. In addition, the AER notes that the contract provides for increased rewards (and penalties) associated with a cost underrun (overrun) where actual expenditure is below (or above) the TOC.

As discussed above, the AER notes KPMG's view that United Energy is likely to be in better position to forecast its work volume requirements that external parties (including the bidders). Accordingly, the AER does not agree that as the tender process required a budget (which includes unit costs and unit volumes) it follows that the tender process demonstrates that United Energy's forecast unit volumes have been market tested. It is on this basis that the AER is not satisfied that United Energy's tender process demonstrates that the total of United Energy's forecast volumes reasonably reflects a realistic expectation of demand forecasts and costs inputs required to achieve the opex objectives. In forming this view the AER has had regard to the opex factors, in particular, the information included in United Energy's proposals and United Energy's actual opex incurred during the 2006-10 regulatory period.

Forecast outsourced unit volumes are closely linked to actual historical volumes

The AER acknowledges that United Energy provided further information which links United Energy's forecast volumes sourced by JEN.[87] United Energy also cited AECOM as supporting evidence that its volume estimates over the 2011–15 regulatory control period are neither material nor unreasonable.[88] The AER has considered the following source material in United Energy's revised regulatory proposal:

- AECOM, UED Asset Management Plan Review

- AT Kearney

[86] In general, the regulatory regime also provides an incentive United Energy to provide conservative volume forecasts as United Energy will retain the benefits of any underspend for five years through the EBSS.

[87] United Energy, *Response to information requested 26 July 2010*, 6 August 2010.

[88] United Energy, *Revised regulatory proposal*, July 2010, p. 51.

- confidential appendix provided by United Energy.[89]

The AER notes that AECOM concluded that overall changes from 2009 volumes are neither material nor unreasonable. In particular AECOM concluded that:

> The proposed Opex quantities are, by and large, similar to those that occurred in calendar year 2009. Work is planned and recorded in UEDs SAP system and quantities can be shown to be accurate. Notable decreases and increases in the Opex quantities for the next regulatory period are as follows:
>
> - Code MZB Routine Maintenance Secondary Zone Substation – an average increase of 395% over 2009 quantities;
> - Code MLB Bulk Replacement Lamp Main Road – an average decrease of 35% over 2009 quantities;
> - Code MRB Bulk Change (Minor Road) – an average increase of 25% over 2009 quantities;
> - Code MRF Faults (Minor Road) – an average increase of 27% over 2009 quantities;
> - Code MRR PL pole Repairs – an average increase of 24.8% over 2009 quantities;
> - Code MOS Service Adjustment – an average increase of 13% over 2009 quantities.
>
> For the remainder of the works, there is no or only a small change to the quantity of work when compared with year 2009 and, overall, quantities remain consistent with those for calendar year 2009.[90]

The AER has compared these cost items against JEN's actual and planned 2009 volumes and United Energy's forecast volumes for these items over the forthcoming regulatory control period. The results of this comparison are provided in table I.5.

[89] United Energy, *Revised regulatory proposal*, Appendix 4, Advice on the optimal design of UED's business model, AT Kearney, July 2010; United Energy, *Initial regulatory proposal*, Appendix D5, UED Asset Management Plan Review, AECOM, November, 2009, p. 3.United Energy, *Response to information requested 26 July 2010*, 6 August 2010.

[90] United Energy, *Initial regulatory proposal*, Appendix D5, UED Asset Management Plan Review, AECOM, November, 2009, p. 3.

Table I.5 Comparison of AECOM and AER on volume change

Code	AECOM calculation	AER calculation - UED average volume for 2012-15 compared with 'JEN 2009 actual'	Difference from AECOM calculation	AER calculation - UED average volume for 2012-15 compared with 'JEN Planned'	Difference from AECOM calculation
MZB	395%	1660%	1265%	2767%	2372%
MLB	35%	No info from United Energy's spreadsheet	Na	No info from United Energy's spreadsheet	Na
MRB	25%	112%	87%	67%	42%
MRF	27%	73%	46%	60%	33%
MRR	24%	41%	26%	37%	13%
MOS	13%	–67%	–80%	-225%	-238%
Total	n.a	144%		36%	

Source: AECOM report, November 2009, p. 3; AER calculation. United Energy provided JAM's actual 2009 volumes for cost items consistent with table 2 in the AT Kearney report in response to AER information request of 26 July 2010.

Table I.5 indicates that the increases above actual volumes or planned 2009 volumes are substantially above the increases identified by AECOM. This compares to JEN 2009 planned volumes (also provided in the AT Kearney report) which indicated an increase of 36 per cent. Further, the AER has reviewed United Energy's forecast volumes for all cost items which United Energy based its forecast on actual or planned JEN 2009 volumes and notes there is an overall increase of 144 per cent based on actual volumes and 36 per cent based on planned volumes. The AER notes that JEN planned volumes are also provided in table 2 of the AT Kearney report. The AER estimates that these volumes relate to approximately $44m of United Energy's outsourced forecasts.[91] In summary, the AER notes that:

- the AER's calculations indicate different results from the line items in AECOM report, and for most case volumes have increased significantly, as detailed in table I.5
- United Energy's proposed average annual volumes for 2012–15 has increased by 144 per cent and 36 per cent compared with JEN's '2009 actual' and JEN planned volumes, respectively.

91 AER's calculation is based on [**word removed CIC**] TCE model provided by United Energy in response to the AER's information requested on 5 February 2010, 24 February 2010. This is consistent with the AT Kearney report which indicates that $38.8m of outsourced opex relates to unit volumes based on historical expenditure.

Accordingly, the AER does not agree with United Energy that forecast outsourced unit volumes are closely linked to actual historical volumes.

United Energy also submitted that it has adopted JEN's planned volumes subject to some minor modifications.[92] The AER notes that AT Kearney has provided volume information in table 3 of its report which is sourced:

- United Energy altered volumes and
- United Energy forecast volumes.

The AER notes that United Energy's opex forecast sourced from 'United Energy altered volumes' accounts for an estimated $37m of United Energy's outsourced opex forecast. The AER also estimates that volume forecasts sourced from 'United Energy volumes' accounts for approximately $8m over the 2011–15 regulatory control period.[93] The AER notes that United Energy has not provided any basis for the 'United Energy forecast volumes' proposed volumes in its revised regulatory proposal.

I.6.2.4 AER conclusion

The AER is satisfied that the component of United Energy's outsourced costs based on annualised services reasonably reflect the efficient and prudent costs in the actual circumstances of United Energy having regard to 6.5.6(e)(1). However, the AER maintains that it is not satisfied that United Energy's outsourced services based on unit volumes ($78.4m) reasonably reflect the opex criteria.

Based on the discussions above, the AER is not satisfied that forecast outsourced work volumes are reasonable as they have not been sufficiently substantiated by robust and transparent information. Thus the AER is not satisfied that all of United Energy's proposed outsourced work volumes in its forecast opex reasonably reflects the efficient costs, costs that would be incurred by a prudent operator in the circumstances of United Energy or a realistic expectation of input costs required, to achieve the opex objectives. The AER position is summarised below:

- The AER accepts that the proportion of outsourced costs associated with annualised services are likely to satisfy the opex criteria in the NER given these costs are not volume based (i.e. these costs are based on a unit price) which have been subject to a competitive tender process.
- The AER considers that unit volumes associated with outsourced services based on 'historical' volumes are not closely linked to historical volumes as represented by United Energy (that is, volumes based on JAM's 2009 planned or actual volumes).
- The AER is not satisfied that unit volumes associated with outsourced services based on the 'United Energy altered volumes' and 'United Energy forecasted

[92] United Energy, *Revised regulatory proposal*, July 2010, p. 51.

[93] AER's calculation is based on [**word removed CIC**] TCE model provided by United Energy in response to the AER's information requested on 5 February 2010, 24 February 2010. Total of $45million is consistent with the AT Kearney report which indicates that $39.6 m of outsourced opex relates to unit volumes based on estimates

volumes' in its revised regulatory proposal reasonably reflect efficiency and prudent costs.

I.6.3 In-house cost forecasts

I.6.3.1 AER draft decision

The AER did not accept the in-house opex forecasts provided in United Energy's initial regulatory proposal. In particular, the AER considered that United Energy's forecasts involved a significant degree of estimation which had not been sufficiently supported by robust and transparent information.[94]

I.6.3.2 Revised regulatory proposal

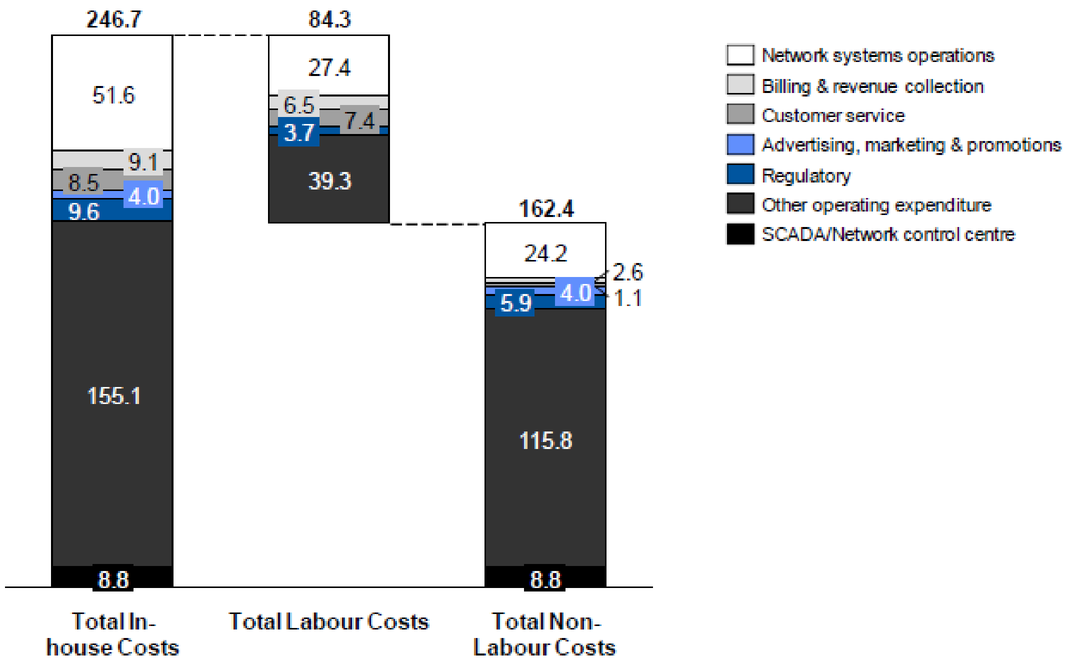
United Energy's revised regulatory proposal separated its in-house cost forecasts into two main categories:[95]

- in-house non-labour costs
- in-house labour costs.

United Energy stated that while it may be appropriate to examine labour costs in terms of 'volume' and 'unit costs', this approach is less appropriate for non-labour costs.[96]

A breakdown of United Energy's in-house costs is shown in figure I.5.

Figure I.5 United Energy's total 5-year in-house opex forecasts ($'m, 2010)



Source: United Energy, *Revised regulatory proposal*, p. 54.

94 AER, *Vic Draft Decision*, June 2010, p. 231.
95 United Energy, *Revised regulatory proposal*, p. 53.
96 ibid., p. 54.

United Energy considered that its revised regulatory proposal substantiated fully its opex forecasts in accordance with the NER. Specifically, United Energy considered that it provided ample evidence to demonstrate that its forecast opex reasonably reflected the opex criteria.[97]

I.6.3.3 Issues and AER considerations

The AER's considerations of United Energy's in-house non labour and in-house labour costs are discussed below.

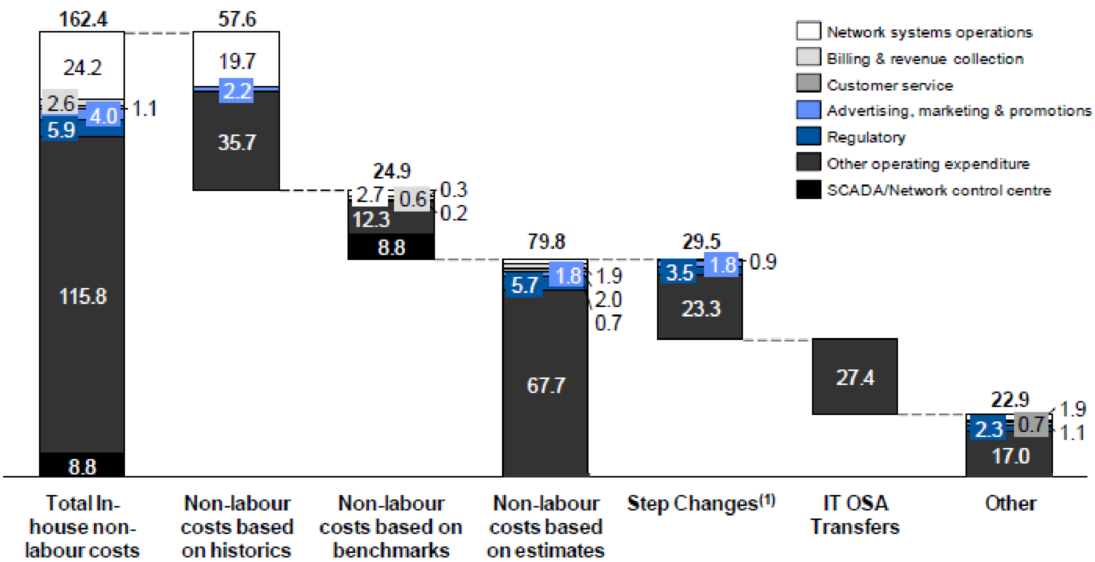
In-house, non-labour costs

KPMG assessed United Energy's in-house, non-labour opex forecasts of $162.4 million (or 66 per cent of total in-house opex), as being based on the following sources:

- historical data
- available comparative cost information and benchmarks
- estimates from United Energy management and independent consultants (engaged by United Energy).[98]

AT Kearney also assessed United Energy's in-house, non-labour costs based on the categories identified by KPMG, though provided greater detail regarding the breakdown of these costs and the basis for the estimate of these cost components.[99] The composition of these costs and the method of estimating these cost categories are provided in figure I.6.

Figure I.6 United Energy's total 5-year in-house, non-labour opex forecasts ($'m, 2010)



Source: United Energy, *Revised regulatory proposal*, p. 55.

97 United Energy, *Revised regulatory proposal*, pp. 61–62.
98 ibid., p. 54.
99 United Energy, *Revised regulatory proposal*, Appendix C-4, pp. 33–38.

Historic information
United Energy's cost estimates for the forthcoming regulatory control period, based on historical costs, represented 35 per cent (or $57.6 million, $2010) of United Energy's in-house, non-labour cost forecasts. The AER notes that 'other operating expenditure' comprised 62 per cent (or $35.7 million, $2010) of forecast opex for this category.

In regard to the individual cost components within this category, AT Kearney has provided further information which itemises the annual costs and the underlying assumptions inherent in these forecasts.[100] The costs itemised by AT Kearney, however, do not explain or substantiate all of the costs in this category. That is, $24.1 million ($2010) of costs are not substantiated by the AT Kearney report, or for that matter, by the KPMG report.[101]

Available comparative cost information and benchmarks
United Energy's cost estimates for the forthcoming regulatory control period, based on available comparative costs, represented 15 per cent (or $24.9 million, $2010) of United Energy's in-house, non-labour cost forecasts. The largest proportion of the costs in this category, approximately 50 per cent (or $12 million, $2010) related to 'other operating costs'.

Further, the AT Kearney report provided a breakdown of these annual costs. AT Kearney noted that these costs are sourced from a combination of:

- historical cost information
- management views
- KPMG benchmarks and experience
- other sources.[102]

The AER is not satisfied, however, that the supporting evidence underlying the annual cost items based on available comparative cost information is consistent with a total opex forecast that reasonably reflects efficient, prudent and realistic costs given the AER's criticisms of the KPMG benchmarks in section I.6. The AER also notes that while certain cost items have not been subject to any external review—they are based on management estimates and/or are dependant on estimated staffing levels—these cost items as a proportion of this cost component are relatively minor.[103] That said, given the AER's concerns with the KPMG benchmarking information, the AER is not satisfied that all of these costs, which represent approximately $24.9 million ($2010) of United Energy's total forecast opex, reasonably reflect efficient and prudent costs.

United Energy management and consultants estimates

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[100] United Energy, *Revised regulatory proposal*, Appendix C-4, p. 33
[101] Specifically, table 9 in the AT Kearney report only covers 60 per cent of the forecast in-house, non-labour costs (based on historical data) over the forthcoming regulatory control period.
[102] United Energy, *Revised regulatory proposal*, Appendix C-4, pp. 35–36.
[103] For example, the PSTN lines costs are based on significantly more employees than forecast in United Energy's internal budgeting models. These costs, however, only represent $1.7 million ($2010) over the forthcoming regulatory control period.

The AER has also reviewed United Energy's in-house, non-labour cost forecasts based on estimates from United Energy's management and KPMG. These costs represent approximately 49 per cent (or $79.8 million, $2010) of United Energy's in-house, non-labour cost forecasts for the forthcoming regulatory control period.[104]

The AER notes that, excluding step changes, the remaining costs of approximately $50 million ($2010) are sourced from a combination of:

- United Energy management estimates and historical data
- KPMG
- undisclosed sources.[105]

Further, the AER notes that approximately $20 million ($2010) of these costs are based on a combination of management costs and undisclosed sources.[106] The AER considers that these costs may not have been independently verified beyond United Energy's management's estimates.[107] The AER also considers that this level of expenditure is closely aligned with the 'other' expenditure category, of $22.9 million ($2010), identified by AT Kearney.[108] The AER notes that no details are provided regarding the 'other' costs category within United Energy's regulatory proposals (including the associated KPMG and AT Kearney reports).

The AT Kearney report also identified $27.4 million ($2010) associated with IT OSA transfers. AT Kearney identified these costs as being related to activities currently undertaken by JAM but which will be taken over by United Energy when it changes to its new business model. AT Kearney further stated that these costs included the infrastructure operation and maintenance required to support the bidders and are therefore not included in the scope of the TCE bids.[109] The AER notes that the assumptions underlying these costs have not been linked to any sources. That said, to the extent that these costs may be related to business as usual costs, the AER considers that these costs may be reasonable.

In-house labour volumes

The AER's draft decision considered that the links between the source material submitted by United Energy and the employee numbers inherent in United Energy's opex forecasts were not well established.[110] Specifically, the AER considered that

[104] The AER notes that these costs included $29.5 million ($2010) comprised of 'step change' costs, debt raising costs and proposed self-insurance allowances. The AER has considered these costs separately as part of the final decision. The AER's assessment is provided in chapter 7.

[105] United Energy, *Revised regulatory proposal*, Appendix C-4, pp. 36–38.

[106] Some of these costs are based on a combination of United Energy's management and KPMG estimates (based on benchmarking). However, it is not possible to determine the proportion of these costs that are based on KPMG estimates as opposed to United Energy management estimates.

[107] As discussed previously within this appendix, the AER considers that KPMG's reports did not assess the assumptions underpinning United Energy's opex forecasts. Rather, the AER considers that KPMG confirmed that United Energy had applied these assumptions consistently in developing its opex forecasts.

[108] United Energy, *Revised regulatory proposal*, Appendix C-4, p. 32.

[109] ibid.

[110] AER, *Draft decision*, p. 233.

United Energy had not substantiated the assumptions upon which its forecast staff numbers were determined.

In response to the draft decision, United Energy’s revised regulatory proposal documented the number and function of employees, and the supporting evidence used to determine the forecast staffing numbers. The supporting evidence consisted of four sources:

- United Energy existing employees
- United Energy historic data
- JAM current organisational data
- United Energy management and expert estimates.[111]

These sources of evidence are considered below.

In assessing United Energy's proposed staffing levels, the AER acknowledges that it would be expected that as a number of services are being brought back in-house there should be a corresponding increase in forecast staffing levels. The issue to be considered, therefore, is the necessary staffing levels required to perform these functions.

United Energy existing employees
The AER notes that this source of evidence only covered 1.2 employees (FTE), but considers this estimate to be reasonable as it is based on existing employees.[112]

United Energy historic data
The AER considers that the ability to estimate employee numbers based on United Energy's historic structure (pre 2002 OSA) may be, to some degree, limited due to changes in the business and the business environment since United Energy last performed these roles internally. The AER also considers that the mix of services previously undertaken internally by United Energy may not necessarily be the same services being transferred internally under United Energy's new business model. Further, the AER considers that the incentives within the regulatory regime were unlikely to have ensured a fully efficient employee structure in 1999 following the recent privatisation of the industry through 1995 and 1996. The AER also considers that other factors, such as advances in technology and associated productivity improvements, would have reasonably led to significant changes in staffing levels throughout this period.

The extent to which the issues identified above or other issues have impacted United Energy's operations over the previous decade have not been discussed within United Energy's regulatory proposal. The AER, however, acknowledges that absent

[111] United Energy, *Revised regulatory proposal*, pp. 59–61.
[112] This represents less than 1 per cent of United Energy's forecast staffing levels. United Energy, *Revised regulatory proposal*, p. 60.

more recent information, United Energy's historical structure is likely to represent a reasonable reference point for estimating required staffing levels.[113]

Jemena Asset Management's current organisational structure

United Energy's proposed staffing levels forecast based on JAM's current organisational structure represented between 23 and 27 per cent of United Energy's total forecast staff.[114] To the extent that the staffing forecasts required for United Energy's new business model reflect the same volume and mix of services undertaken by JAM, the AER considers that JAM's current organisational structure is a reasonable reference point for estimating required staffing levels. That said, the AER notes that JAM provides services to a number of businesses such that any estimates derived from JAM staffing numbers may overestimate United Energy's staffing requirements.

United Energy management and expert estimates

The AER notes that between 18 and 39 per cent of United Energy's total staff levels are forecast based on estimates provided by United Energy's management, or consultants engaged by United Energy.[115] United Energy considered that reports provided by both KPMG and AT Kearney fully substantiated these estimates.[116]

The AER notes that estimated staffing numbers are based on the following sources, or a combination of the following sources:

- existing employees
- historical information
- JAM
- management estimates
- KPMG.[117]

113 United Energy's proposed staffing levels included between 33 and 49 per cent of staff forecast based on United Energy's historical structure. The range reflects different assumptions regarding corporate services staff for which the supporting evidence is a combination of United Energy's historical data and management and consultant estimates. United Energy, *Revised regulatory proposal*, p. 60.

114 The range reflects different assumptions regarding corporate services staff for which the supporting evidence is a combination of Jemena Asset Management's current organisational structure and management and consultant estimates. United Energy, *Revised regulatory proposal*, pp. 59–61.

115 The supporting evidence underlying United Energy's organisational headcount (FTE) identified categories of staff that were estimated based on a combination of United Energy's historical structure, JAM's current structure and United Energy's management and consultant estimates. The range of employees assumed by the AER as being forecast based on management estimates reflects different assumptions as to the predominant source of supporting evidence. The maximum value assumed the combined forecasts are based entirely on management estimates, while the minimum value considered the forecasts are not based on management estimates at all. The associated percentages reflect a total staffing level of 121.15 (FTE). United Energy, *Revised regulatory proposal*, pp. 59–61.

116 United Energy, *Revised regulatory proposal*, p. 61.

117 United Energy, *Revised regulatory proposal*, Appendix C-4, pp. 18–21.

As discussed previously though, the AER considers that KPMG's report simply confirmed that United Energy's forecast opex assumptions are consistent with those reflected in United Energy's opex models. That is, the AER considers that a detailed analysis of United Energy's underlying assumptions with respect to internal staffing levels has not been undertaken. The AER notes that KPMG stated that:

> We have reviewed the staffing structures assumed by UED's departmental structure under its new business model and received supporting explanations of the rationale for their structure…..We noted that the explanations provided were mutually consistent with other assumptions on which the Expenditure forecasts are based and reflected a rational process of planning of actual anticipated requirements undertaken by UED functional heads.
>
> … We reviewed the assumed structures of these departments and found that the assumptions of staffing structures are consistent with our understanding of the **minimum functions** that would be required for a distribution business UED's size operating under UED's business [emphasis added].
>
> …we conclude that the assumptions of positions and employment costs that underpin UED's forecasts of internal expenditure, have a supportable basis and are **consistent with UED's assumptions** of its business model for the 2011-2015 Regulatory Period [emphasis added].[118]

The AER also notes that the KPMG report referred to a limited level of benchmarking analysis surrounding the overall staffing structures inherent in United Energy's new business model.[119] This benchmarking analysis, however, only considered between 23 and 53 per cent of United Energy's proposed staffing numbers forecast.[120] Further, the AER notes that KPMG did not consider whether this benchmarking supported the efficiency of United Energy's forecast opex.[121]

In regard to the supporting evidence in the AT Kearney report, the AER notes, as highlighted previously, that between 18 and 39 per cent of United Energy's staffing numbers may be based on United Energy management estimates.[122] This suggests that between $15.3 million ($2010) and $33.1 million ($2010) of in-house labour costs are not based on any external review.[123] As discussed above, the AER considers that sources of information that rely on JAM's staffing numbers may not be appropriate. The AER considers that this provides additional uncertainty regarding the basis of these forecasts.

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118 United Energy, *Regulatory proposal*, Appendix C-1, pp. 75–76.

119 The staff structures identified by KPMG as falling within their 'sphere of business expertise' represent the Finance and administration, Regulatory services, Legal and key contract, and CEO office functions detailed in table 5.5 of United Energy's revised regulatory proposal. United Energy, *Regulatory proposal*, Appendix C-1, p. 75.

120 The AER has estimated this range based on the same assumptions used previously to determine the percentage of United Energy's total staffing levels forecast based on estimates provided by United Energy's management, or KPMG. These high and low estimates were then cross-referenced to the categories within table 5-6 of United Energy's revised regulatory proposal which corresponded to the categories that KPMG identified as falling within their 'sphere of business expertise'. The AER notes that the level of detail provided by United Energy and KPMG was insufficient to undertake more robust analysis.

121 United Energy, *Regulatory proposal*, Appendix C-1, p. 75.

122 United Energy, *Revised regulatory proposal*, Appendix C-4, pp. 18–20.

123 This range reflects the AER's consideration that between 18 and 39 per cent of United Energy's staffing numbers may be based on United Energy management estimates, multiplied by the total in-house labour costs, totalling $84.3 million, as forecast by United Energy.

In-house labour costs

The AER's draft decision stated that while United Energy had provided economy-wide and utility industry salary benchmark reports, United Energy had not clearly demonstrated the link between the reports and the salary estimates in its internal corporate budgeting model.[124] Further, the AER noted that United Energy had neither explained nor substantiated the inclusion of a salary bonus for all staff in forecast costs.[125]

To address the AER's concerns, United Energy's revised regulatory proposal included a report from AT Kearney which presented 'detailed tables that demonstrated the linkage between the salary benchmark reports and the salary estimates used in United Energy's regulatory proposal'.[126]

The AER has reviewed United Energy's revised proposal, including the AT Kearney report. In reference to the AT Kearney report, the AER notes that no explanations are provided for the differences between United Energy's proposed salaries and the corresponding salaries within the benchmark industry reports. United Energy's proposed salaries, however, are broadly consistent with the industry benchmark reports. Further, the differences are symmetric, and largely balance in aggregate. That is, some estimates are above the industry benchmark, while others are below.

Inclusion of bonus payments

Consistent with the draft decision, the AER does not accept the inclusion of bonus payments proposed by United Energy.[127] The AER considers that performance bonuses generally reflect individual employee productivity improvements and as such, should result in cost savings for United Energy.[128] The AER, therefore, is not satisfied that United Energy has appropriately quantified the net cost impact of individual performance and productivity bonuses in light of the expected productivity gains.[129]

Further, the AER considers that this approach may not be appropriate given the incentive based regulatory framework. The AER considers that accepting United Energy's bonus forecasts would effectively represent a shift from an incentive based regulation framework, to cost of service regulation.[130]

I.6.3.4 AER conclusion

Based on the discussions above, the AER is not satisfied that all of United Energy's in-house, non-labour costs are reasonable as they have not been sufficiently substantiated by robust and transparent information. Further, the AER is not satisfied

124 AER, *Draft decision*, p. 22.

125 ibid., p. 22.

126 United Energy, *Revised regulatory proposal*, p. 56.

127 AER, *Draft decision*, p. 232.

128 That is, while labour costs may increase, total costs per unit of output will decrease.

129 This approach is consistent with the AER’s final determination for ActewAGL. AER, *Australian Capital Territory distribution determination 2009–10 to 2013–14, Final decision*, April 2019, pp. 58–59.

130 $12.6 million ($2010) has been calculated based on United Energy's assumption of typical performance from its employees. The AT Kearney report stated that this assumption resulted in the forecast of a 15 per cent bonus for the majority of staff, and 7.5 per cent for administrative and clerical staff. United Energy, *Revised regulatory proposal*, Appendix C-4, p. 30.

that all of United Energy's proposed in-house, labour costs and labour volumes are reasonable as they have not been sufficiently substantiated by robust and transparent information. Thus, the AER is not satisfied that United Energy's in-house opex forecasts reasonably reflect the efficient costs that would be incurred by a prudent operator in the circumstances of United Energy or a realistic expectation of input costs required, to achieve the opex objectives. The AER's position is summarised below.

- The AER is not satisfied that United Energy's in-house, non-labour costs reasonably reflect the efficient and prudent expenditure or realistic cost inputs required to achieve the opex objectives.

- The AER accepts that the proportion of in-house, labour volumes based on existing United Energy employees, United Energy's historical structure, and to some degree JAM's current organisational structure reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives.

- The AER is not satisfied that the proportion of in-house, labour volumes based United Energy's management and consultant estimates reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives.

- The AER accepts that the in-house, unit labour rates based on economy-wide and utility industry salary benchmark reports reasonably reflect the efficient costs of achieving the opex objectives.

- The AER is not satisfied that the inclusion of bonus payments in the in-house, unit labour rates forecasts reasonably reflect the efficient costs of achieving the opex objectives.

I.7 Issues and AER considerations—Current business model counterfactual O&M forecast

I.7.1 AER draft decision

United Energy’s current business model is centred on:

- a single outsourced contract (its operating services agreement (OSA)) under which the asset management, planning, construction and maintenance of its network is outsourced to Jemena Asset Management (JAM), which is ultimately owned by United Energy’s minority shareholder (Singapore Power)[131], and

- a small management structure that conducts strategic management and corporate governance activities both within and through services provided by its majority shareholder, Diversified Utility Energy Trust (DUET).

Accordingly, in the draft decision the purpose of the AER's counterfactual estimate was to estimate the cost United Energy would incur if it continued with its current business model, rather than adopting its new business model.

The AER determined the base opex amount of this counterfactual by summing:

131 United Energy, *Regulatory proposal*, p. xvii.

- JAM’s 2008 costs in servicing United Energy’s network, as reported by JAM to United Energy and verified by PriceWaterhouseCoopers (PWC)—subject to the exclusion of certain allocations of Jemena Ltd corporate costs, meter data services costs, and making an adjustment to reflect that 'other' operating costs should also be allocated across non-standard control services, and

- United Energy’s 2009–10 internal costs as found in its internal corporate opex budgeting model—subject to the costs associated with its new business model being removed and other adjustments as outlined in the draft decision

The AER did not include within this base year estimate the management and financial services fees that United Energy forecasts it will pay its related parties (DUET and AMP Capital Investors) over the forthcoming regulatory control period as it was not satisfied these costs reasonably reflected efficient costs or costs of a prudent operator in United Energy's circumstances.

The AER noted it would update United Energy's base year costs for its final decision following consideration of JAM's 2009 costs of servicing United Energy's network.

I.7.2 United Energy revised regulatory proposal

United Energy states that its new business model necessitates a 'bottom up' forecasting approach, rather the revealed cost approach adopted by the AER.

That said, United Energy acknowledges that the AER's revealed cost approach is appropriate to employ in 'stress testing' its forecast, subject to amendments regarding what its considers are a number of inappropriate adjustments and escalation factors.[132]

The amendments to the AER's approach that United Energy claims should be made to provide a reasonable stress test are:

- the inclusion of the audited transfer between capital and operating expenditure set out in United Energy's regulatory accounts

- the inclusion of certain costs the AER removed on the basis of being non-recurrent

- the inclusion of an appropriate margin on the costs incurred by JAM in providing outsourced services to United Energy

- the inclusion of the costs of services provided by DUET and AMPCI, and

- amendments to the AER's approach of projecting 2009 costs to 2010, including the appropriate CPI escalation to adopt.[133]

United Energy concluded that the amended calculation illustrates that its initial opex forecast for its new business model is reasonable and should be accepted by the AER.[134]

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[132] United Energy, *Revised regulatory proposal*, p. 37.
[133] United Energy, *Revised regulatory proposal*, p. 65.
[134] United Energy, *Revised regulatory proposal*, p. 37.

I.7.3 AER considerations

In this section, the AER discusses the general issue of using a current business model continuation counterfactual to 'stress test' United Energy's new business model forecast, the appropriate emphasis placed on benchmarking and historical costs, and the appropriate regulatory treatment of transformational costs. The AER then considers the adjustments proposed by United Energy to the AER's draft decision counterfactual estimate associated with JAM's costs and UEDH's costs, respectively.

I.7.3.1 Overarching considerations

'Stress testing' United Energy's new business model forecast

In its revised proposal, United Energy argues:

> It is noted that UED's 'reference line' calculation in its original Regulatory Proposal projected 2008 audited costs to 'stress test' UED's operating expenditure forecasts. UED accepts that the AER's 'year 4' method could be used in a similar manner, even though it cannot provide a reasonable forecast of UED's operating expenditure because UED's new business model is a marked departure from existing arrangements.[135]

Elsewhere in its revised proposal, United Energy goes further to claim:

> UED's new business model necessitates a 'bottom up' forecasting approach, rather than a 'year 4' approach as adopted by the AER's Draft Decision. A year 4 approach does not represent a valid forecast, and as such UED would be breaching the Rules if it developed a forecast of its operating expenditure in that way.[136]

It seems inconsistent to the AER that United Energy acknowledges that a counterfactual estimate based on a continuation of its current business model is appropriate under the NER to 'stress test' its forecast, but if after having compared this estimate against United Energy's new business model forecast, among other considerations, the AER is not satisfied United Energy's opex forecast reasonably reflects the opex criteria, arguing that substituting its forecast with this counterfactual estimate is not appropriate.

The NER requires United Energy to submit a total opex forecast which it considers is required in order to achieve the opex objectives.[137] The AER must accept United Energy's forecast if it is satisfied the total forecast reasonably reflects the opex criteria. If the AER is not satisfied, it must not accept United Energy's forecast, and must replace it with a forecast the AER is reasonably satisfied reflects the opex criteria.

In deciding whether the AER is satisfied it must have regard to, among other things, United Energy's actual and expected opex during the current regulatory control period and pervious periods.[138] In its rule determination on chapter 6A, the AEMC confirmed a service provider's actual costs from the current regulatory control period may be

[135] United Energy, *Revised regulatory proposal*, p. 63.
[136] United Energy, *Revised regulatory proposal*, p. 37.
[137] NER, cl.6.5.6(a).
[138] NER, cls.6.5.6(c)–(e).

used as a basis for establishing the reasonableness of the cost estimates provided by the service provider in the subsequent period.[139]

United Energy's current opex (subject to any transformation costs being removed) naturally reflect the costs presently incurred under its current business model. Adjusting these costs for expected changes in cost inputs, network scale, new regulatory obligations, and other like factors, as well as efficient and prudent cost changes associated with renewing its current outsourcing arrangements, reflect the costs it would incur if it continued its current business model into the forthcoming regulatory control period.

The reason the AER has chosen to compare this counterfactual estimate against United Energy's forecast, is because the AER considers, properly constructed, that this counterfactual reflects efficient costs, costs of a prudent operator in United Energy's circumstances, and a realistic forecast of demand and cost inputs. If United Energy's forecast compared reasonably well against this estimate, then the AER would accept United Energy's forecast as reasonably reflecting the opex criteria. However, if after making this comparison, and taking into account other relevant considerations, the AER is not satisfied United Energy's opex forecast reasonably reflects the opex criteria, then the AER considers it is entirely appropriate for the AER to substitute United Energy's forecast with the counterfactual estimate, given the AER considers the counterfactual estimate does reasonably reflect the opex criteria.

Forming a view that United Energy's new business model forecasts do not reasonably reflect the opex criteria and substituting them with an estimate of United Energy's costs under a continuation of its current business model does not mean that the AER doesn't expect United Energy will transition to its new business model. Rather, it means that the AER is not satisfied United Energy's forecast reasonably reflect the opex criteria and the AER has substituted this amount for an estimate the AER is satisfied reasonably reflect the criteria.

Whether United Energy transitions to its new business model is a matter entirely for it to determine. In no way does the basis on which the AER accepts or substitutes United Energy's forecast bind the actions or business decisions of United Energy. If United Energy continues on its business transformation process and this leads to lower costs compared to the AER's current business model counterfactual estimate, then United Energy will be financially rewarded for these efficiencies under the EBSS. However, if its new business model leads to higher costs then it will be financially penalised, as is appropriate given the symmetrical nature of the EBSS.

Emphasis placed on historical costs vs. benchmarking

The 'starting point' for the current business model counterfactual discussed above are United Energy's historical costs. Accordingly, historical costs feature prominently in the AER's assessment.

The NER requires the AER to have regard to both United Energy's actual and estimated opex in the current and previous regulatory control periods, as well as benchmarking expenditure that would be incurred by an efficient DNSP over the

139 AEMC, *Rule determination—National Electricity Amendment (Economic regulation of transmission services) Rule 2006 No.18*, 16 November 2006, p.93.

relevant regulatory control period.[140] Accordingly, a relevant question to consider is the respective emphasis that it is appropriate to place on these opex factors.

Frontier Economics (commissioned by United Energy) considers that in determining if United Energy's opex forecast meets the NER requirements, the AER should place greater emphasis on benchmarking than United Energy's current and historical costs.

United Energy quotes, among others, the following section of Frontier Economics' advice in its revised proposal:

> In my view, the best approach for the AER to adopt in assessing whether UED's forecast operating expenditure is efficient is through some form of benchmarking analysis.
>
> As noted above, benchmark operating expenditure are one of the operating expenditure factors that the AER must have regard to when assessing whether a DNSP's proposed operating costs meet the requirements of Rule 6.5.6(c) (see Rule 6.5.6(e)(4)). As also noted above, I think that in light of the unsustainability of the costs under UED's current OSA with JAM, more weight should be placed on benchmarking to derive forecast operating expenditure than on UED's (or JAM's) historical costs.
>
> Accordingly, I think that the AER should put less weight on its current extrapolation approach and focus on a proper cost benchmarking exercise for UED.[141]

Frontier Economics' opinion that the AER should place greater weight on benchmarking is premised on the current OSA costs being 'unsustainable' into the future. Frontier Economics states it understands the OSA costs are unsustainable for the following commercial and regulatory reasons:

- commercial reason—JAM's costs in servicing the OSA appear to be higher than the price negotiated under the contract, which makes it unlikely United Energy could achieve a similar (low) price for these services in the future
- commercial reason—the OSA gives risk to a number of governance issues and exposes United Energy to a number of risks of underperforming its service standards and hence not meeting its opex objectives, and
- regulatory reason—United Energy has had considerable difficulty in the past persuading regulators that its outsourcing arrangements yield the provision of operating services at efficient costs.[142]

Frontier Economics acknowledges the first reason is not a concern with the AER's approach as:

> The AER's methodology utilises JAM's actual costs of servicing UED's network (rather than the price UED paid for these services under the OSA). This has the advantage of avoiding questions surrounding the potential

[140] NER, cls.6.5.6 (e)(4)-(5).
[141] Frontier Economics, *Meaning and application of National Electricity Rule 6.5.6(c)—A report prepared for Johnson Winter & Slattery*, July 2010, pp.14-15.
[142] Frontier Economics, *Meaning and application of National Electricity Rule 6.5.6(c)—A report prepared for Johnson Winter & Slattery*, July 2010, pp.11-12..

> under-recovery of JAM's costs under the present OSA contract. This means that the AER's estimated costs should not be understated as a result of referring to a historical underpriced contract that is unlikely to be available to UED in the future.[143]

Frontier Economics suggests United Energy may not be able to secure prices for the forthcoming regulatory control period similar to the costs JAM incurred over the OSA period if JAM has been 'under-servicing' United Energy's network or requires a margin above its costs. In section I.7.3.2, the AER responds to these issues, concluding that neither issues have been substantiated.

As for the 'regulatory' reason, the AER's approach to assessing related party margins permits the recovery of these margins so long as they adhere to what the AER has identified (taking into account the opex criteria, revenue and pricing principles and the NEO) as the legitimate economic reasons for the inclusion of a margin. United Energy has not responded to the reasons put forward by the AER in the draft decision, and so has not raised any points of disagreement with the AER's approach to outsourcing arrangements (outlined in chapter 6).

The AER acknowledges that in assessing DNSPs' forecasts, it must have regard to both benchmark expenditure and historical expenditure. While the AER has had regard to both in this decision, the AER has placed greater emphasis on historical costs. The AER's general approach to the assessment of each of the Victorian DNSPs opex forecasts, including its reasons for placing greater emphasis on historical costs than benchmarking is explained chapter 7.

Frontier Economics' view that the AER should place greater weight on benchmarking rather than historical costs in assessing United Energy's opex forecast is based on a view that the OSA arrangements are unsustainable. Based on the arguments put forward to support this contention, the AER has not found this to be the case, with the exception of the loss currently being earned by JAM in servicing the contract. As noted above and confirmed by Frontier Economics, the AER's approach has adequately addressed this issue by adopting JAM's current actual costs rather than the current contract charges.

Treatment of transformational costs

Frontier Economics also advised on the appropriate treatment of transformational costs, commenting that:

> On the issue of transformational costs, I agree with the AER that it is inappropriate to include these costs in the determination of the business-as-usual reference line comparator, given that these costs would not be incurred if the previous business model had been retained. Therefore, these costs should be excluded from the reference line.
>
> However, I believe that UED should be entitled to recover any forthcoming regulatory period costs arising from the adoption of a new business model where that model leads to overall operating expenditures that reasonably reflect efficient and prudent costs. Such future costs may be one-off (such as the cost of implementing staff redundancies) or recurrent (such as the cost of additional services). To the extent the reference line is used to provide a

143 Frontier Economics, *Meaning and application of National Electricity Rule 6.5.6(c)—A report prepared for Johnson Winter & Slattery*, July 2010, p.13.

> like-for-like comparison to the costs of the new business model, I believe that the reference line should reflect any costs associated with additional services provided under the new business model that are required for reasons of prudent risk management.[144]

The AER maintains its draft decision approach to exclude new business model transformational costs from its current business model counterfactual estimate. There is agreement between the AER, Frontier Economics and United Energy on the appropriateness of this, given such costs would be avoided in the scenario United Energy continued its current business model.[145]

There is also agreement between the AER, Frontier Economics and United Energy that one-off transformational costs (such as redundancy costs) are appropriately included and accepted within United Energy's new business model forecast, if United Energy can demonstrate that its total forecast reasonably reflects efficient costs and costs of a prudent operator in United Energy's circumstances.

Though the AER notes United Energy's new business model only includes the hiring of new United Energy, UEDH or PIES employees and not the firing of any existing employees (that the AER is aware of). Therefore, any forecast redundancies costs could only be those associated with the redundancy of JAM employees. For these costs to be accepted in United Energy's opex forecast, it would need to be demonstrated that paying the redundancy costs of another business, after it ceases its contractual relationship, reflects the good and prudent business practices of an operator in United Energy's circumstances. It is difficult for the AER to see how such payments could be viewed as efficient or prudent.

Additionally, Frontier Economics makes references to 'additional services' provided under the new business model which should be added to the current business model counterfactual estimate. United Energy also advocates, in principle, an adjustment to account for 'additional services' though does not make such an adjustment.[146] It is not clear from either United Energy's proposal or Frontier Economics' report what these additional services are, why they are required for prudent risk management, or how an appropriate adjustment would be made. Given the lack of clarity and substantiation over how this issue has been presented in United Energy's proposal, the AER has not been convinced that such an adjustment is appropriate under the NER.

I.7.3.2 Jemena Asset Management (JAM) costs

Regulatory accounts transfer of capitalised JAM overheads to opex

United Energy states each year it processes an adjustment to its regulatory accounts to ensure consistency with the expenditure forecasts in the 2006 EDPR and United Energy's capitalisation policy. This adjustment reclassifies overheads which are capitalised and included within the capex fee charged by JAM, and reports them as opex instead of capex.[147]

144 Frontier Economics, *Meaning and application of National Electricity Rule 6.5.6(c)—A report prepared for Johnson Winter & Slattery*, July 2010, p.10.
145 United Energy, *Revised regulatory proposal*, p.71.
146 United Energy, *Revised regulatory proposal*, p.97.
147 United Energy, *Revised regulatory proposal*, p.71.

United Energy states that, in the draft decision, the AER rolled the adjusted capex (that is, exclusive of JAM overheads) into United Energy's RAB, but used the unadjusted opex (that is, also exclusive of JAM overheads) when establishing United Energy's base opex forecast. It states the AER has therefore erred by not including these overheads in either the RAB or the opex forecast.[148]

The AER has reviewed United Energy's regulatory accounts and has verified that the transfer occurs, as outlined by United Energy.

The AER agrees with United Energy that an adjustment to its base opex for these capitalised overheads is appropriate for the reason outlined by United Energy, and acknowledges that no such adjustment was made in the draft decision.

That said, the AER does not agree that the adjustment should reflect the full $7.4m amount, as United Energy contends, for the following reason. The $7.4m amount is the adjustment for United Energy's whole distribution business, and does not reflect the amount that should be allocated to non-standard control services. In accordance with clause 6.5.6(b)(2), the AER has made an adjustment that is consistent with United Energy's approved cost allocation method (CAM)—this results in a negative adjustment of $0.8m. This adjustment reduces the capitalised overheads transfer amount from $7.4m to $6.6m. The AER has incorporated the $6.6m amount in its base opex forecast.

Removal of non-recurrent costs

In the draft decision, the AER did not include certain costs in the base opex—that were incurred by Jemena Ltd and allocated to both JEN and United Energy—on the basis that they were non-recurrent. A PriceWaterhouseCoopers (PWC) report submitted by JEN in its original proposal clearly identified these costs as non-recurrent, and JEN had removed these costs itself from its base opex for this reason. The AER accepted this aspect of JEN's proposal. Accordingly, the AER's adjustment simply brought United Energy's current business model counterfactual estimate into line with JEN's proposed base opex on this issue.

Despite this reasoning, United Energy argues there was 'no basis for the AER's assertion that these costs are non-recurrent'.[149]

The AER maintains its position from the draft decision for the reasons set out in the draft decision. That said, the draft decision opex in relation to the Jemena Ltd allocations for United Energy (and JEN) were based on 2008 amounts. As flagged in the draft decision, the AER has updated these amounts for 2009 amounts (or estimated 2009 amounts where 2009 actuals are not available). This adjustment is outlined further in section I.6.2.

'Under-servicing' by JAM

United Energy states:

> A further issue raised by Phillip Williams is the possibility that JAM is under-servicing UED's network to a point where existing cost levels are unsustainable. As noted in information submitted by UED with its original

[148] United Energy, *Revised regulatory proposal*, p.71.
[149] United Energy, *Revised regulatory proposal*, p.70.

> Regulatory Proposal, the possibility of cost-cutting by JAM to unsustainable levels is a matter that has been considered by UED's Board, and was also a consideration in adopting the new business model. Evidently, the future provision of services under the OSA would need to be provided at sustainable cost levels, and cost projections should reflect this operational requirement. For the purposes of amending the AER's 'year 4' approach, however, UED has not included a specific allowance to address this issue.[150]

United Energy's argument that JAM has an incentive to under-service its network is based on the reasoning that the negative service performance impacts from under-serving (of which JAM would be financially penalised for) only materialise slowly. Accordingly, JAM has the opportunity to financially benefit now from the reduced costs of over-servicing, while exiting the arrangements with United Energy before the negative service performance impacts (and associated STPIS penalties) materialise.

Neither United Energy or Frontier Economics has presented the AER with evidence that demonstrates JAM has acted in the way United Energy contends it is incentivised to act. Indeed, rather then JAM attempting the exit the contractual arrangement with United Energy before the negative STPIS effects materialise, JAM has been in a formal arbitration process over its 'right to match' any contracts United Energy offers other parties after the expiry of JAM's OSA. JAM's actions suggest it is keen to maintain its relationship with United Energy, servicing its network beyond the OSA period.

Further, JAM's shareholders are also minority shareholders in United Energy. So even by exiting the service relationship, JAM's shareholders could not avoid the STPIS effects of under-servicing unless it completely sold its ownership stake in United Energy. Accordingly, JAM's incentives may not be what United Energy suggest they are.

JAM margin

United Energy argues that a profit margin should be added to JAM's 2009 actual costs, referencing Frontier Economics to support this principle.

The specific JAM margin proposed by United Energy is [**percentage removed CIC**] per cent. It supports this by reference to:

- a report by Ferrier Hodgson, submitted by United Energy to the AER in the context of its AMI application, that accordingly to United Energy demonstrates 6 per cent is a reasonable margin, and
- noting the AER's comment in the JGN final decision that benchmark profit margins extend from around 3 per cent to more than 12 per cent.

The AER does not consider a margin on the JAM costs reasonably reflects efficient costs or the costs of a prudent operator in United Energy's circumstances. This issue is addressed in chapter 6—Outsourcing arrangements.

150 United Energy, *Revised regulatory proposal*, p.81.

I.7.3.3 United Energy Distribution Holdings (UEDH) costs

In the draft decision the AER stated that, unlike for the other Victorian DNSPs, it was not relying on the reported regulatory account expenditure as United Energy's actual 2009 costs (as reflected in the regulatory accounts) will include a significant amount of costs associated with its transition to the new business model.[151]

Instead, the AER relied on United Energy’s 2009–10 internal costs as provided in its internal corporate opex budgeting model, with the costs associated with its new business model removed. While the AER noted these costs were estimates (which was a limitation), the AER considered they had the benefit of being a bottom up construction from individual cost categories. Accordingly, the AER was able to review the model line-by-line and remove transitional costs and other costs associated with United Energy’s new business model.

United Energy's revised proposal did not accept this source or estimate for non-JAM costs in the current business model counterfactual estimate.

In its revised proposal, United Energy's counterfactual estimate adopts $[**number removed CIC**]m for 'UED / PIES' costs (which is inclusive of transformational and regulatory submission costs, though United Energy subsequently removes these costs, which provides an amount of $[**number removed CIC**]m). United Energy referenced its regulatory accounts as the source of these figures. To this amount, United Energy adds $[**number removed CIC**]m for DUET costs and $[**number removed CIC**]m for AMPCI costs. This results in an adjusted non-JAM base opex estimate of $[**number removed CIC**]m.

The AER requested United Energy explain how the UED / PIES costs reconcile with United Energy's 2009 regulatory accounts. United Energy's response stated that while these costs were included in the regulatory accounts they were not itemised.

The AER is concerned that the $[**number removed CIC**]m for UED / PIES is significantly more than the $[**number removed CIC**]m in the regulatory accounts for costs paid by United Energy to UEDH in 2009. The UEDH costs consist of the total costs United Energy incurs in sourcing services from DUET, AMPCI, Macquarie and PIES (and any additional internal costs incurred by UEDH).

It appears that the UED / PIES amount in United Energy's revised proposal either:

- does not reconcile with the regulatory accounts—in which case the AER could not place great reliance on this amount, or
- includes internal United Energy costs (that is, distinct from internal UEDH costs) which are in addition to the costs paid to UEDH—in which case the AER could also not utilise this amount as United Energy has previously informed the AER that the internal United Energy costs from 2009 predominantly relate to new business model costs. These new business model costs should be excluded from this analysis as they would not be incurred under a continuation of United Energy's current business model.

[151] The other two reasons raised in the draft decision on why the AER was not using the regulatory accounts reported expenditure related purely to JAM's costs.

Accordingly, the AER has substituted the $[**number removed CIC**]m UED / PIES costs with the $[**number removed CIC**]m UEDH costs as reported in United Energy's 2009 regulatory accounts. Further adjustments to these UEDH costs are discussed below.

Based on the additional material provided in United Energy's revised proposal, the AER now accepts DUET's and AMPCI's costs in providing services to UEDH (and ultimately, to United Energy). Though the AER notes this acceptance errs in United Energy's favour as a component (that is, a component of unknown magnitude) of DUET's costs are likely to include shareholder costs which would more appropriately be borne by United Energy's shareholders and not recovered from consumers. This issue is discussed further in section 6.7.2.

Accordingly, the AER accepts, in principle the inclusion of the UEDH costs (which include the DUET and AMPCI costs). However, there is one adjustment which should be made to the reported 2009 amount, being the exclusion of the reported UEDH costs which United Energy's auditors were not able to verify (discussed in section 6.7.2)—an adjustment of $**[number removed CIC].**

Additionally, the AER did not include the following adjustments as proposed by United Energy:

- the exclusion of 7/11 transitional costs
- the exclusion of the regulatory submission costs

There is some uncertainty about whether the UEDH costs from which the AER adopted as the source of these costs includes these costs. The AER has erred in United Energy's favour but assuming these costs are not included within the UEDH costs, meaning the AER has not made United Energy's proposed adjustments.

Accordingly, the AER has adopted a base opex estimate of $**[number removed CIC]**m for non-JAM costs in its current business model counterfactual O&M forecast.

The AER notes that the draft decision estimate of UEDH's costs (excluding DUET and AMPCI costs) was $7.2m. If the AER added the $[**number removed CIC**]m of DUET and AMPCI costs, this would result in an *estimate* of UEDH's 2009 costs of $[**number removed CIC**]m (derived from United Energy's internal budgeting model). This compares with UEDH's *actual* 2009 costs of $[**number removed CIC**]m (as reported in United Energy's regulatory accounts).

The discrepancy between these two amounts and the difficulty of United Energy's internal budgeting model to accurately predict 2009 costs—a year which at the time was in the very near future and in which United Energy's business conditions were predicted to be essentially unchanged from the past—raises issues regarding the reliability of United Energy's model to accurately predict its internal costs over the 2010-2016 period—a future period in which United Energy's business conditions will be substantially changed from the past, and for which a number of assumptions have been made by United Energy to derive these forecasts.

The objective in the draft and final decisions has been to estimate United Energy's non-JAM costs under its current business model. While the AER has departed from its draft decision in terms of where it sources this estimate, given United Energy did not accept the draft decision the AER considers this issue is not closed under the NER. Accordingly, it is open to the AER to revisit the source of this information in reviewing and responding to United Energy's revised proposal. This review has uncovered that the AER's original source (derived from United Energy's budgeting model) significantly overestimated this amount. Therefore the AER has not adopted that source, and has instead adopted the regulatory accounts amount, subject to the exclusion of the transformational costs and regulatory submission amounts, as outlined above.

I.7.3.4 Other issues

United Energy also stated the AER escalated its 2009 actual opex:

- to a 2010 amount using the difference in United Energy's opex allowance in the last two years of the current regulatory period, however in doing so, the AER should have reviewed the ESCV's approach to setting the allowance (correcting any errors made) and updated the ESCV's assessment to account for outturn information, including 'inaccuracies' in the ESCV's assumptions, and
- 2009 actual opex to 2010 dollars using historical inflation, when it should have used forecast inflation.[152]

The AER addresses these issues in chapter 7. In summary the AER has corrected for an inconsistency in the ESCV's 2006 EDPR, to roll forward United Energy's 2009 base year costs to 2010, but does not consider that United Energy's proposed inflation adjustment is appropriate.

AER conclusion

As per the draft decision, the AER has aggregated JAM's costs and UEDH's costs, making adjustments where appropriate, to reflect a counterfactual estimate of a continuation of United Energy's current business model into the forthcoming regulatory control period. In its revised proposal, United Energy supported adopting such a counterfactual estimate to 'stress test' its forecast, which was after all, a variant of the 'reference line' forecast in its initial proposal. Though United Energy raised amendments it considered should be made to the specific inputs into the AER's draft decision counterfactual estimate.

As per the draft decision, AER has sourced the JAM costs from United Energy's regulatory accounts with a CAM adjustment for non-standard control services and excluding the management fee Jemena Ltd pays to Singapore Power. United Energy accepted each of these adjustments.

On the further amendments proposed by United Energy:

- the AER has maintained its exclusion of one-off costs from Jemena Ltd (the AER does not accept United Energy's position that the AER has not demonstrated these

[152] United Energy, *Revised regulatory proposal*, p.81.

costs are non-recurrent), though the AER has updated this adjustment to reflect the different composition of one-off costs in 2009. The AER has also maintained its exclusion of Jemena Ltd's corporate strategy costs.

- the AER accepts United Energy's proposal that an adjustment to reflect the transfer of JAM's capitalised overheads to opex is appropriate, though the AER does not consider the adjustment should be as large as that proposed by United Energy for the reasons stated in this section, and
- the AER is not satisfied that a margin added to JAM's costs is appropriate, based on the reasons presented by United Energy. In chapter 6, the AER sets out what it considers are the legitimate economic reasons for the inclusion of a margin under the NEL and NER. United Energy has not justified the JAM margin against these reasons.

United Energy's 2009 regulatory accounts also contained an error, reporting prescribed metering maintenance costs within the prescribed services (exc. metering)—that is, standard control services—column. The AER has corrected this error in its counterfactual estimate. The AER also notes there are no metering services classified as standard control services in the forthcoming regulatory control period.

As for UEDH costs, the AER accepts in principle the inclusion of the DUET and AMPCI costs and the exclusion of the transformation and regulatory submission costs. However, the AER has not been able to verify the starting point used by United Energy for the non-JAM costs—which is an amount of $[**number removed CIC**]m that United Energy describes as "UED / PIES" costs. The AER requested United Energy explain how this amount was derived and to reconcile this amount with its regulatory accounts. In response United Energy's did not provide this reconciliation, instead stating that while the amount was included in the regulatory accounts it was not individually itemised. According, the AER has adopted the "UEDH" costs from United Energy's 2009 regulatory accounts, but excluded the amount United Energy states could not be verified by its auditors. This amount implicitly includes the DUET and AMPCI costs while also excluding the transformational and regulatory submission costs.

Table I.6 sets out the adjustments discussed in this section.

Table I.6 Base O&M—Continuation of United Energy's current business model counterfactual estimate for 'stress test' analysis against United Energy's new business model forecast ($'m, per annum, 2010)

Cost category	Draft decision	Revised proposal	Final decision
JAM costs			
Operating (reg accounts)	65.5	63.4	62.6
less Excluded services	-2.6	-2.6	-2.6
less Management fees	[c-i-c]	[c-i-c]	[c-i-c]
less Corporate strategy costs	[c-i-c]	-	[c-i-c]
less One-off costs	-1.6	-	-0.6
Maintenance (reg accounts)	18.6	18.6	18.4
less Metering	-	-	-1.1
plus Capitalised overheads transfer	-	+7.4	+6.6
plus Margin	-	[c-i-c]	-
Subtotal (JAM costs)	**79.5**	**89.2**	**82.9**
United Energy internal / UEDH costs			
UED / PIES	11.2	[c-i-c]	N/A
less Transformational costs	-4.1	-2.9	N/A
less Regulatory submission costs	-1.4	-1.4	N/A
DUET	-	[c-i-c]	N/A
AMPCI	-	[c-i-c]	N/A
UEDH (reg accounts)	N/A	N/A	[c-i-c]
less Costs not verified by auditors	N/A	N/A	[c-i-c]
Subtotal (United Energy / UEDH)	**5.7**	**15.0**	**7.2**
Other			
less GSLs	-0.1	-0.1	-0.1
plus Benchmark efficiencies	-0.2	+2.2	+2.1
Subtotal (Other)	**-0.3**	**2.1**	**2.0**
TOTAL	**85.0**	**106.3**	**92.2**

Source: AER draft decision, United Energy[153], AER analysis

The purpose of this section has been to establish an efficient and prudent base level of opex that United Energy would be expected to incur if it continued with its current business model into the forthcoming regulatory period. United Energy argued:

> Once a valid base year cost is established it must be rolled forward with appropriate adjustments to reflect changes in output quality and quantities, changes in the real prices of inputs, and other factors.[154]

The AER agrees that changes in real prices of inputs should be taken account, and this is set out in appendix K—Real cost escalators. To the extent that United Energy's reference to changes in output 'quantities', refer to changes in the scale of its network, the AER also agrees these are appropriate, however it is not clear this is what United Energy meant.

The AER does not accept United Energy's statement that changes in output 'quality' should be taken into account. Under the NER, the opex forecast is to reflect the efficient, prudent and realistic costs required to 'maintain' service and network quality, reliability, safety and security. Costs that reflect forecast changes to service quality are only permitted in the opex forecast if mandated by a regulatory obligation or requirement.[155]

In the next section, the AER integrates the base opex in this section with the network scale, cost escalations, step change and self insurance amounts from other sections of the final decision. The AER then compares this estimate of the total costs United Energy would incur if it continued its current business model against forecast proposed by United Energy based on its the new business model.

I.8 AER conclusion

Based on the analysis above, the AER is not satisfied that United Energy's proposed outsourced work unit volumes, in-house non-labour costs, in-house labour volumes and in-house labour rates in its forecast opex for the forthcoming regulatory control period meet the opex objectives and criteria in the NER.

The AER notes that United Energy provided further information in its revised proposal in support of its forecast opex. However, the AER is not satisfied that all of United Energy's outsourced and in-house costs reasonably reflect efficient, prudent and realistic cost inputs on the basis that United Energy provided unit volume forecasts to the bidders which were based on management or consultant estimates coupled with the incentive for United Energy to inflate these forecasts. The AER's position is summarised below:

- The AER accepts that the proportion of outsourced costs associated with annualised services are likely to satisfy the opex criteria in the NER given these costs are not volume based (that is, these costs are based on a unit price) which have been subject to a competitive tender process.

[153] United Energy, *Revised regulatory proposal—Appendix C16*, p.1.
[154] United Energy, *Revised regulatory proposal*, p.63.
[155] NER, cls.6.5.6(a)-(c).

- The AER also considers that unit volumes associated with outsourced services based on historical volumes (that is, volumes based on JAM's 2009 volumes) are likely to represent efficient volumes over the forthcoming regulatory control period. However, the AER notes that the proportion of outsourced costs that United Energy purported to be based on historical cost are in fact 144 per cent above historical costs.

- The AER notes that as part of its tender process, United Energy provided forecast unit volumes for outsourced services to the bidders and these forecast volumes determined the budgeted costs from the tender process. In turn these budgeted costs determined United Energy's forecast opex for outsourced services for the forthcoming regulatory control period. The AER notes KPMG's statement that United Energy's management is best placed to estimate costs. That said, the AER notes United Energy's view that there was a strong incentive on United Energy and bidders to ensure that bids were based on the best possible information regarding expected unit prices and work volumes. United Energy also stated that the contract priced by the bidders for the purposes of the regulatory proposal places the contractor's entire gross margin at risk depending on cost efficiency and service quality. In addition, the contractor bears 50 per cent of costs incurred above the annual target cost over the regulatory control period, which is largely a function of the tendered budget. The contractual arrangements set out in the tender would provide an incentive for the tender's to submit best estimates.

- The AER considers that these contractual arrangements may provide an incentive for unit volumes determined by United Energy to be inflated above efficient volumes as United Energy will share with the service provider in any penalty or reward associated with any cost over-runs and under-runs respectively. In addition, the regulatory regime also provide an incentive for United Energy to determine inflated work volume forecasts as United Energy will retain the benefits of any underspend for an additional five years through the EBSS.

- The AER is not satisfied that United Energy's in-house, non-labour costs reasonably reflect the efficient and prudent expenditure or realistic cost inputs required to achieve the opex objectives.

- The AER is not satisfied that the proportion of in-house, labour volumes based United Energy's management and consultant estimates reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives.

- The AER is not satisfied that the inclusion of bonus payments in the in-house, unit labour rates forecasts reasonably reflect the efficient costs of achieving the opex objectives.

- The AER notes that while United Energy has relied on KPMG to support its forecast opex, KPMG's has stated that it was not tasked with assessing whether United Energy's opex forecast satisfied the opex criteria in the NER. Accordingly, the AER does not consider that the KPMG report can be relied on to support the magnitude of the United Energy's forecast opex. Further, as discussed, the AER considers that United Energy forecasts may be higher than necessary given the incentives in the regulatory regime and

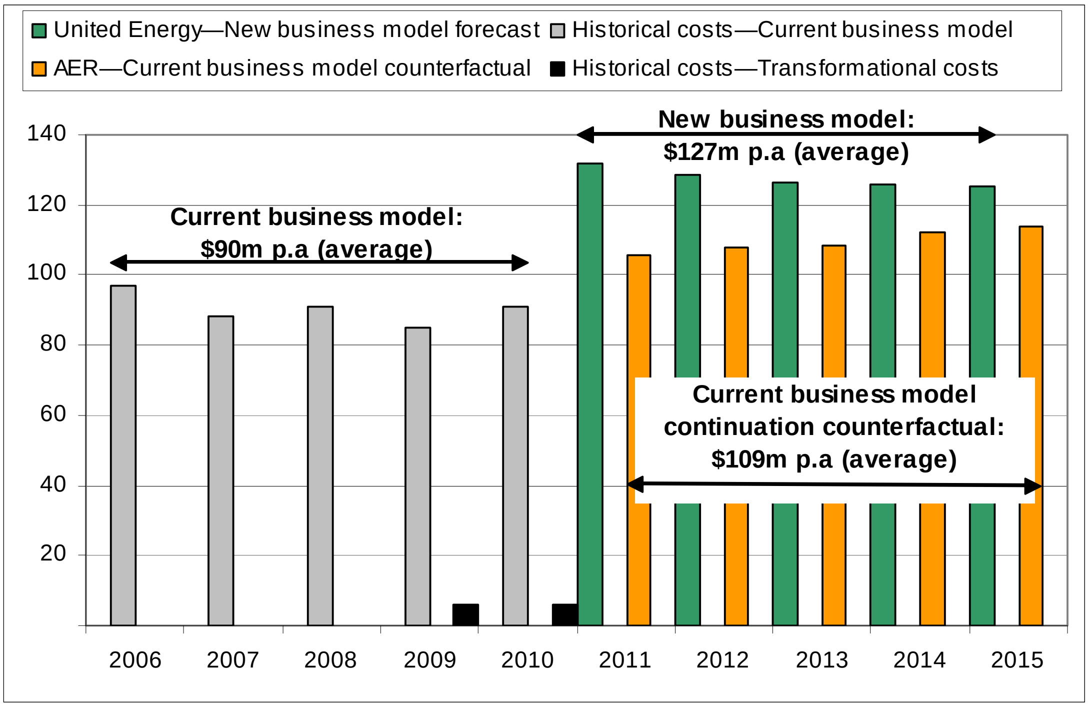
- The AER in assessing United Energy's new business model forecasts over the forthcoming regulatory control period has placed emphasis on United Energy's actual costs given that these costs can be assumed to be efficient costs based on the incentives to reduce costs in the regulatory regime. .

United Energy has also submitted a counterfactual base opex forecast assuming a continuation of its current business model into the forthcoming regulatory control period. According to United Energy, this current business model counterfactual estimate can be used to 'stress test' the reasonableness of its new business model forecast.

United Energy proposed a base opex amount of $106.3 million per annum for this counterfactual exercise. However, for the reasons set out in the previous section the AER found this was not a reasonable estimate and has substituted this amount for an estimate of $92.2 million. The most significant adjustments related to corporate costs. As discussed, United Energy has not substantiated the "UED / PIES" cost category. The AER substituted this amount with the "UEDH" costs (which include the PIES costs) which were verifiable against United Energy's 2009 regulatory accounts.

The AER added to the $92.2 million per annum base opex forecast the step change, scale and real labour and material cost escalations amounts determined by the AER elsewhere in this decision. This resulted in an estimate of $109m per annum, on average, if United Energy continued its current business model. This compares with the much higher amount of $127m per annum, on average, which is United Energy's opex forecast under its new business model. This comparison is shown in Figure I.7.

Figure I.7 Total O&M—United Energy new business model forecast vs. AER current business model continuation counterfactual estimate O&M ($'m, 2010)



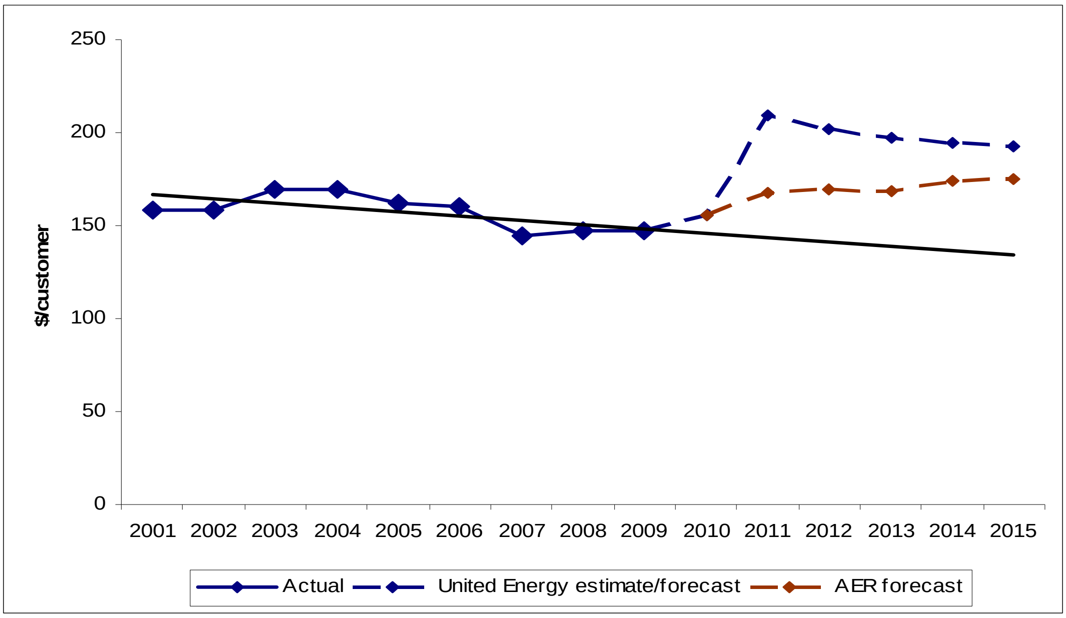
Source: United Energy revised proposal RIN templates, AER analysis

As noted above, the AER is not satisfied that United Energy's revised proposal based on its new business model total opex forecast reasonably reflects efficient, prudent and realistic costs. The AER has assessed the components of United Energy’s opex forecast and has identified a number of issues. These issues predominantly relate to outsourced unit volumes which are significantly above historical levels without adequate justification, and management estimates of in-house costs which have not been properly substantiated by United Energy.

The AER's concerns over the robustness and reasonableness of United Energy's new business model forecast is furthered by the analysis in Figure I.7 which demonstrates this forecast is significantly above the costs United Energy would be expected to incur under a continuation of its current business model.

United Energy's new business model also does not compare favourably against certain benchmarking analysis. For example, Figure I.8 shows the ratio of United Energy's opex and customer numbers historically compared to its forecast. The AER's consideration of benchmarking it set out in appendix H—Benchmarking.

Figure I.8 United Energy opex per customer—Historical and forecast ($2010)



Source: AER analysis

Given these considerations, the AER is not satisfied that United Energy total opex forecast of $637.5 million reasonably reflects the efficient, prudent and realistic costs of meeting the opex objectives over the forthcoming regulatory control period. The AER has adjusted United Energy's forecast to reflect the AER's current business model counterfactual estimate—a total of $547.5 million—which is the minimum adjustment the AER considers necessarily in order to reflect efficient, prudent and efficient costs. This adjustment is shown in Table I.7.

The AER's substituted forecast is a 15.0 per cent increase in United Energy total opex over the current regulatory period of $476.1 million.

Table I.7 Final decision—United Energy operating and maintenance forecast ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy revised proposal	131.9	128.3	126.3	125.7	125.3	**637.5**
AER adjustment	-26.5	-20.7	-18.1	-13.2	-11.4	**-90.0**
AER final decision	105.4	107.6	108.2	112.4	113.9	**547.5**

Source: United Energy revised proposal PTRM, AER analysis

As noted previously, the reason the AER has chosen to compare a current business model continuation counterfactual estimate against United Energy's new business model forecast, is because the AER considers, properly constructed, that this counterfactual reflects efficient costs, costs of a prudent operator in United Energy's circumstances, and a realistic forecast of demand and cost inputs. If United Energy's new business model forecast had compared reasonably well against this estimate, then the AER would have accepted United Energy's forecast as reasonably reflecting the opex criteria. However, having made this comparison, and taking into account other relevant considerations, the AER is not satisfied United Energy's opex forecast reasonably reflects the opex criteria. Accordingly, the AER considers it is necessary for the AER to substitute United Energy's forecast with the AER's counterfactual estimate, given the AER considers the counterfactual estimate does reasonably reflect the opex criteria.

Forming a view that United Energy's new business model forecasts do not reasonably reflect the opex criteria and substituting them with an estimate of United Energy's costs under a continuation of its current business model does not mean that the AER does not expect United Energy will transition to its new business model. Rather, it means that the AER is not satisfied United Energy's forecast reasonably reflects the opex criteria and the AER has substituted this amount for an estimate the AER is satisfied reasonably reflects the criteria.

Whether United Energy transitions to its new business model is a matter entirely for United Energy to determine. In no way does the basis on which the AER accepts or substitutes United Energy's forecast bind the actions or business decisions of United Energy. If United Energy continues on its business transformation process and this leads to lower costs compared to the AER's current business model counterfactual estimate, then United Energy will be financially rewarded for these efficiencies under the EBSS. However, if its new business model leads to higher costs then it will be

J Scale escalation

The AER recognises that as distribution networks grow in size, intuitively the distribution businesses will face an increase in the costs of operating and maintaining their networks. Scale escalation is typically expressed in terms of an annual rate of growth in opex resulting from the increase in the size of the distribution network. The annual growth rate of the network is determined with reference to network growth drivers that are considered to approximate the resultant growth in the network and hence, opex. The annual growth rate is used to escalate base opex and is then adjusted downwards to reflect identified economies of scale. The efficiency savings from economies of scale accrue to the DNSP (and in turn customers) because the cost per unit of operating and maintenance activities falls as the scale of network operating and maintenance activities increases because these activities can be conducted more efficiently.

J.1 Regulatory requirements

As noted in chapter 7, each Victorian DNSP (with the exception of United Energy) proposed an allowance for scale escalators as a component of their total proposed forecast operating expenditure for the 2011–15 regulatory control period.

The assessment of scale escalation is relevant to the AER's assessment of the total of the forecast operating expenditure included in each DNSP's building block proposal for the forthcoming regulatory control period. Clause 6.5.6(c) of the NER states that the AER must accept the forecast of required operating expenditure of a DNSP that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the forthcoming regulatory control period reasonably reflects:[1]

> (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.

Specifically, this appendix assesses the proposed allowance and what the level of efficient expenditure for scale escalation which a prudent operator, in the actual circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the operating expenditure objectives.[2]

The opex objectives are contained in clause 6.5.6(a) of the NER. A DNSP is required by clause 6.5.6(a) of the NER to include in its building block proposal the total forecast opex for the regulatory control period that the DNSP considers is required to:

[1] NER, cl. 6.5.6(c).
[2] NER, cl. 6.5.6(c).

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) maintain the quality, reliability and security of supply of standard control services; and

(4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

The assessment in this appendix primarily raises the issue of whether the growth drivers and the application of these drivers proposed by the DNSPs are required to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.[3] However, the AER also considers opex objectives (3) and (4) are relevant to particular areas of this assessment.

In deciding whether or not the AER is satisfied that the total opex forecast reasonably reflects the opex criteria, the AER must have regard to the opex factors in clause 6.5.6(e) of the NER. If the AER is not satisfied that the total opex forecast reasonably reflects the opex criteria, the AER must not accept the opex forecast.[4] If the AER does not accept a forecast opex proposal in accordance with clause 6.5.6(d), clause 6.12.1(4)(ii) of the NER states that:

> The AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider’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.

Under clause 6.12.3(f)(2) of the NER, this estimate must be the minimum adjustment to the proposed forecast opex necessary to comply with the NER.

As is discussed further in this appendix, the AER considers that the operating expenditure factors in clauses 6.5.6(e)(1), (2), (3), (5) and (7) are relevant to this assessment. The AER also recognises that other instruments, industry standards and previous regulatory decisions are relevant to this assessment.

J.2 AER draft decision

In the draft decision, the AER considered the information included in and accompanying each Victorian DNSP's building block proposals as required by clause 6.5.6(e)(1) of the NER. The AER considered that the growth drivers and adjustments for economies of scale efficiencies proposed by the Victorian DNSPs did not result in an approximation of network growth that reasonably reflected a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[5] In particular, the AER considered that the Victorian DNSPs' proposed scale opex was not appropriate to meet or manage the expected demand for standard control services

3 NER, cl. 6.5.6(a)(1).
4 NER, cl. 6.5.6(d).
5 NER, cl. 6.5.6(c)(3).

over the forthcoming regulatory control period, as required by clause 6.5.6(a)(1) of the NER.

The DNSPs' initial proposals contained the growth rates, scale adjustments and opex scale escalation increases for the forthcoming regulatory control period in Table J.1.

Table J.1 Victorian DNSP initial proposals on scale escalation opex (per cent, per annum)

	Gross growth rate[a]	Economies of scale adjustment[b]	Net growth rate[c]	Proposed scale opex ($'m, 2010)
CitiPower	5.1	45.0	2.8	21.1
Powercor	3.6	35.2	2.3	56.7
JEN	–0.3	–	–0.3	–3.1
SP AusNet	1.7	52.8	0.8	13.1
United Energy	–	–	–	–

Source: AER, *Draft decision, appendix J*, p. 85

[a]The growth in opex before economies of scale efficiencies are taken into account.

[b]The expected savings associated in terms of a dollar of incremental opex (for example, CitiPower's opex associated with network growth will (on average) be reduced by 45 cents for every dollar of incremental opex due to efficiency savings. The economies of scale adjustments were calculated by the AER from the DNSPs' initial proposal models.

[c]Net growth rate = gross growth rate x (1 – economies of scale adjustment)

In the draft decision, the AER considered that applying the net growth rates in Table J.2 would result in an approximation of network growth that would form part of a total forecast opex that reasonably reflected a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives as required by clause 6.5.6(c)(3) of the NER. The AER concluded that the scale escalation expenditure shown in Table J.3 would form part of a with a total forecast opex that would enable the Victorian DNSPs to meet or manage the expected demand for standard control services for the forthcoming regulatory control period.[6]

6 NER, cl. 6.5.6(a)(1).

Table J.2 AER draft decision on scale escalation opex (per cent, per annum)

	Gross growth rate	Economies of scale adjustment	Capex/opex trade-off	Net growth rate
CitiPower	1.0	53.3	16.5	0.3
Powercor	1.4	57.1	8.0	0.5
JEN	1.1	57.6	7.2	0.4
SP AusNet	1.5	62.5	5.7	0.5
United Energy	1.0	57.6	4.6	0.4

Source: AER, *Draft decision, appendix J*, pp. 105, 109; draft decision models.

Table J.3 AER draft decision on scale escalation opex ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	0.1	0.2	0.3	0.4	0.5	**1.4**
Powercor	0.6	1.2	1.8	2.3	2.9	**8.8**
JEN	0.2	0.3	0.5	0.7	0.8	**2.5**
SP AusNet	0.6	1.1	1.7	2.2	2.8	**8.4**
United Energy	0.3	0.6	0.9	1.2	1.5	**4.6**

Source: AER, *Draft decision, appendix J*, page 113

J.3 Victorian DNSP revised regulatory proposals

Each of the Victorian DNSPs except for United Energy applied an explicit escalation to its revised base opex proposal for growth in the size of the distribution network, although some AER analysis was required to determine the proposed gross growth rates, economies of scale factors and the amount of escalation. United Energy provided the AER with growth drivers, net growth rates and growth opex[7], but reiterated that the tender process for outsourced services addresses unit prices and volumes.[8]

The Victorian DNSPs apart from SP AusNet generally accepted the AER's draft decision regarding the selection of scale escalation growth drivers, but considered that zone substation capacity was a more appropriate driver than the number of zone substations. These DNSPs also noted that zone substation capacity is consistent with the AER's decision on scale escalation in the recent South Australian distribution determination.[9] SP AusNet disagreed with the draft decision network growth driver

7 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 64.

8 ibid., pp. 81–83.

9 CitiPower, *Revised regulatory proposal* 2011 to 2015, 21 July 2010, pp. 221–222; Powercor, *Revised regulatory proposal* 2011 to 2015, 21 July 2010, pp. 209–210; JEN, *Revised regulatory proposal* 2011–15, 20 July 2010, pp. 120–121; United Energy, *Revised regulatory proposal*, pp. 82–83.

for the number of distribution transformers, the use of the number zone substations, and the use of a simple average weighting of the network growth drivers.[10]

In general, the Victorian DNSPs did not accept the majority of the AER's draft decision on the adjustments to the growth rates for economies of scale and opex associated with the trade off between capex and opex. JEN stated it would only accept the AER's economies of scale adjustments on the condition that commercial margins paid to Jemena Asset Management (JAM) were included. JEN also proposed a separate gross growth factor for IT opex.[11] In addition, the AER notes that some of the Victorian DNSPs proposed significantly different economies of scale adjustments in their revised proposals in comparison to their initial regulatory proposals.

Section J.6 of this appendix presents additional detail on the revised proposals and the AER's assessment and conclusions for the final decision. The Victorian DNSPs' revised proposal gross growth rates, economies of scale adjustments and net scale opex increases for the forthcoming regulatory control period are provided in Table J.4.

Table J.4 Victorian DNSP revised proposals on scale escalation opex (per cent, per annum)

	Gross growth rate	Economies of scale[b]	Net growth rate	Revised scale opex ($'m, 2010)
CitiPower[a]	2.3	42.9	1.3	6.7
Powercor[a]	2.3	32.3	1.5	28.7
JEN[c]	2.4	57.6	1.0	8.4
SP AusNet[d]	2.0	43.6	1.1	20.7
United Energy[e]	–	–	0.8	–

Source: AER analysis of Victorian DNSPs' revised regulatory proposals, Victorian DNSPs' RINs, and Victorian DNSPs' cost escalation models.
[a]CitiPower and Powercor's proposed scale opex increases are slightly different to their revised proposals as data for these two businesses were resubmitted in response to a request for further information by the AER. Their growth rates have been adjusted to remove the effects of input cost escalation.
[b]CitiPower and Powercor's economies of scale factors were calculated by the AER and JEN's is based on conditional acceptance of draft decision.
[c]Although JEN applies an overall average annual net growth rate of 0.95 per cent in its forecast data model, the effective net growth rate (calculated as the average annual rate growth from 2010 to 2015) is closer to 3.0 per cent. JEN's intention is to apply the 'customer number' growth driver to opex and the 'network growth' driver to maintenance expenditure, but its forecast data model appears to apply a network growth driver to opex and maintenance.
[d]SP AusNet's total growth rates and economies of scale are calculated on the basis that scale escalation is applied to maintenance expenditure only.
[e]Although United Energy's opex forecast is not based on the 'year 4' roll forward model, United Energy provided a net growth rate in its revised proposal (p. 83).

[10] SP AusNet, *Electricity Distribution Price Review*, *Revised regulatory proposal*, July 2010, pp. 194–195.
[11] JEN, *Revised regulatory proposal*, pp. 119–122.

J.4 Submissions

The AER received submissions on scale escalation from the Energy Users Association of Australia, the Energy Users Coalition of Victoria and EnergyAustralia.

J.5 Consultant review

In assessing the Victorian DNSPs' proposed scale escalation, the AER engaged Nuttall Consulting to review and make recommendations on the AER's approach to scale escalation, including the appropriateness of the network growth drivers, and the application of these drivers. Nuttall Consulting also reviewed the DNSPs' forecasts for these network growth drivers to assist the AER in assessing whether the Victorian DNSPs' revised proposals for scale escalation reasonably reflect the opex criteria in clause 6.5.6(c) of the NER. This is discussed further in section J.6.

J.6 Issues and AER considerations

In assessing the revised proposals, it is important to establish a framework to ensure that the AER is able to assess and determine whether it is satisfied the scale escalation forecasts reasonably reflect the opex criteria in clause 6.5.6(c) of the NER. In reaching its final decision, the AER must have regard to the opex factors in clause 6.5.6(e) of the NER including (but not limited to) information provided in the Victorian DNSPs' revised proposals, stakeholder submissions, relevant publicly available information, and actual and expected operating expenditure.

This section assesses the following:

- the Victorian DNSPs' proposed selection of growth drivers
- the forecasts for these growth drivers and
- the Victorian DNSPs' proposed method for calculating the network growth drivers, and allocation of these growth drivers to operating and maintenance expenditure categories.

Sections J.6.6 and J.6.7 examine the adjustments to the selected growth drivers, which are:

- economies of scale, and
- capex / opex trade-off (acceleration of the capex renewal program may result in a reduction in required maintenance activity)

Section J.6.9 contains a comparison of the AER's conclusions on the scale escalation opex allowance against the Victorian DNSPs' revised proposals and actual opex to ascertain the reasonableness of the allowance provided through its assessment. The AER's conclusions are presented in section J.7.

J.6.1 Scale escalation

J.6.1.1 Submissions

The EUCV submitted that it supports the AER's approach to scale escalation, and agrees that the elements used by the AER to develop its opex scaling factor have a sound basis.[12]

However, the EUCV also submitted that the application of a price cap implicitly provides the Victorian DNSPs with greater revenue than that assessed as reasonable by the regulator if forecast increases in demand and/or consumption are exceeded. This results in an implicit allowance included in the regulatory decision to provide revenue to DNSPs as a result of scale escalation. The EUCV therefore considers that the AER's approach might lead to a higher scaling factor than is appropriate.[13]

EnergyAustralia submitted that it had concerns with the AER's approach to scale escalation, including the interrelationship between scale escalation and the EBSS.[14] EnergyAustralia submitted:[15]

> The AER has inappropriately developed approaches and criteria to assess proposed expenditure that do not enable a distributor to recover at least its efficient costs.

EnergyAustralia considers the AER's approach is based on unreliable, high level mathematical functions that do not account for relevant factors, and then test the outcomes using an inappropriate and statistically invalid method.[16] EnergyAustralia also considers the AER should forecast requirements at a more granular level of detail, taking into account additional maintenance requirements stemming from new assets and the condition of the asset base over the regulatory control period.[17]

J.6.1.2 Issues and AER considerations

The price cap issue raised by the EUCV was also raised by the ECCSA in relation to the South Australian draft distribution determination.[18] Consistent with the AER's response in that review, the AER notes that under the NER, the AER's assessment of a DNSP's costs is conducted using a building block assessment, regardless of the particular form of control. This assessment determines the annual revenue requirement for the DNSP, which reflects both expected changes in unit costs, and the scale of the DNSP's operations. The particular form of control determines how the annual revenue requirement may be recovered by the DNSP.

Under a weighted average price cap, a DNSP is exposed to the risk that it may not achieve its annual revenue requirement if demand is greater or less than expected during the building block assessment. The fact that a DNSP is subject to a weighted

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12 Energy Users Coalition of Victoria (EUCV), *Submission to the AER - 2010 AER review of Victorian Electricity DBs, EUCV response to AER Draft Decision*, August 2010, pp. 39–40.

13 ibid.

14 EnergyAustralia, *EnergyAustralia submission on AER draft regulatory determination for Victorian distributors*, 19 August 2010, pp. 10–14.

15 ibid., p. 11.

16 ibid.

17 ibid., p. 13.

18 AER, *ETSA draft distribution determination 2010–2015*, p. 213.

average price cap does not, in itself, mean that the DNSP will receive an implicit allowance for scale escalation.

In response to EnergyAustralia's concern regarding the interrelationship between the EBSS and scale escalation, the AER notes that scale escalation is a relevant factor in determining a DNSP's efficient forecast opex over the forthcoming regulatory control period. The EBSS rewards or penalises a DNSP over the regulatory control period based on actual expenditure relative to the forecast. Further, as discussed in chapter 14, the AER will adjust the Victorian DNSPs' forecast expenditure for actual growth in line with the growth adjustments identified in this chapter in determining the carryover amounts in the EBSS. As a result the Victorian DNSPs will not be rewarded or penalised based on the AER's scale adjustments contained in the final decision. The AER also (as discussed in chapter 13) does not consider that a negative carryover amount will deny the Victorian DNSPs a reasonable opportunity to recover at least their efficient costs. The issue of recovery of at least efficient costs is discussed in detail in chapter 16.

In response to EnergyAustralia's other concerns about the AER's methodology, the AER does not use mathematical functions, but rather a selection of growth drivers that act as a proxy for network growth. The network growth rates are then adjusted for efficiencies resulting from economies of scale. The AER has described in detail its method in the draft and final decision.

This approach has largely been agreed on by the Victorian DNSPs, and is also broadly consistent with the approach taken in the recent South Australian distribution determination and by previous regulators. Further, Nuttall Consulting, in its opex escalation review for the AER considered that on the basis that asset volumes and capacity are drivers of operating expenditure, the scale drivers selected by the AER provide good coverage of the overall network asset base.[19]

The AER's top down analysis (discussed in section J.6.9) is not meant to be a statistical analysis, but rather a high level cross check to provide some context for the net growth rates determined by the AER's scale escalation. The AER considers it is appropriate, having regard to clause 6.5.6(e)(3) of the NER to test its scale escalation approach in this regard.

In addition, the AER notes EnergyAustralia's interpretation of the requirement in section 7A(2) of the NEL that the AER must assess a DNSP's proposed expenditure to *enable* the DNSP to recover at least its efficient costs. Section 7A(2) of the NEL requires the AER to provide a distributor with *a reasonable opportunity* to recover at least its efficient costs. The AER considers based on the general acceptance by the Victorian DNSPs and independent assessment by Nuttall Consulting that the AER's approach to scale escalation does provide the Victorian DNSPs with a *reasonable opportunity* to recover at least their efficient costs.

[19] Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010, p. 5.

J.6.2 Selection of growth drivers

J.6.2.1 AER draft decision

In the draft decision, the AER noted that the Victorian DNSPs' proposed growth drivers did not reflect the physical homogeneity and interconnectivity of the network. The DNSPs' initial proposals contained ten different growth drivers,[20] resulting in growth rates from –1.6 per cent per annum to +5.2 per cent per annum.[21] However, the growth in the actual physical network requiring maintenance and the number of customers a DNSP is required to service is relatively similar across the DNSPs.[22]

The AER considered growth factors based on physical metrics such as line length and the number of distribution transformers and zone substations resulted in forecasts of opex that most closely reflect the actual growth in operating and maintenance activity levels and are more likely to reasonably reflect the opex criteria in clause 6.5.6(c) of the NER.

In the draft decision, the AER adopted two growth drivers for each Victorian DNSP:

- a composite network growth driver calculated as a simple average of the annual growth in line length and the number of distribution transformers and zone substations over the forthcoming regulatory control period
- the annual growth in customer numbers over the forthcoming regulatory control period.

J.6.2.2 Victorian DNSP revised regulatory proposals

In their revised proposals the Victorian DNSPs generally accepted the AER's draft decision on the following growth drivers:

- Customer numbers
- Distribution transformers (number)
- Line length (km)

As mentioned above, CitiPower, Powercor, JEN and United Energy did not agree with the AER in its use of the number of zone substations as a driver and submitted that growth in zone substation capacity is more appropriate.[23]

SP AusNet did not accept the AER's draft decision on the composite network growth driver. In its revised proposal, SP AusNet proposed growth rates based on the number of power transformers, distribution feeders and lagged line length. The AER notes that the choice of lagged line length is not explicitly mentioned in SP AusNet's

[20] Network replacement cost, Full Time Equivalent working hours, customer numbers, peak demand, energy consumption, lagged customer numbers, line length, lagged line length overhead, lagged line length underground and zone substations.

[21] See tables J.2 to J.5 of appendix J of the draft decision.

[22] See table J.6 of appendix J of the draft decision.

[23] CitiPower, *Revised regulatory proposal*, pp. 221–222; Powercor, *Revised regulatory proposal*, pp. 209–210; JEN, *Revised regulatory proposal*, pp. 120–121; United Energy, *Revised regulatory proposal*, pp. 82–83.

revised proposal, but is used in SP AusNet's opex model.[24] The AER also notes that the number of zone substations has not been proposed in SP AusNet's revised proposal, but SP AusNet included this driver as a component of the network growth driver in its initial regulatory proposal.[25]

Table J.5 to Table J.9 contain of the Victorian DNSPs' revised proposal growth drivers.

24 SP AusNet, *Revised regulatory proposal*, p. 194.

25 In its initial regulatory proposal SP AusNet adopted customer numbers, lagged customer numbers, line length, lagged overhead line length, lagged underground line length and the number of zone substations, per SP AusNet's opex model. See table J.5 of appendix J of the draft decision.

Table J.5 Citipower revised proposal growth drivers (per cent)

	2010	2011	2012	2013	2014	2015
Customer number growth	**1.81**	**2.30**	**1.87**	**1.38**	**1.20**	**1.80**
Composite network growth driver						
Line length growth	3.15	3.21	3.40	3.39	3.34	3.39
Distribution transformer growth	1.82	1.81	1.82	1.81	1.82	1.81
Installed zone substation capacity growth	4.68	2.24	2.19	1.75	3.86	3.13
Composite network growth	**3.22**	**2.42**	**2.47**	**2.32**	**3.01**	**2.78**

Source: CitiPower cost escalation model.

Table J.6 Powercor revised proposal growth drivers (per cent)

	2010	2011	2012	2013	2014	2015
Customer number growth	**1.88**	**1.94**	**1.93**	**1.91**	**1.85**	**1.74**
Composite network growth driver						
Line length growth	1.70	1.73	1.75	1.81	1.84	1.83
Distribution transformer growth	1.81	1.81	1.81	1.81	1.81	1.81
Installed zone substation capacity growth	2.53	2.05	4.02	2.50	3.38	3.64
Composite network growth	**2.01**	**1.86**	**2.53**	**2.04**	**2.34**	**2.43**

Source: Powercor cost escalation model.

Table J.7 JEN revised proposal growth drivers (per cent)

	2010	2011	2012	2013	2014	2015
Customer number growth	**1.76**	**1.95**	**1.74**	**1.43**	**1.25**	**1.37**
Composite network growth driver						
Line length growth	1.20	1.32	1.35	1.35	1.43	1.31
Distribution transformer growth	3.02	3.37	3.63	3.83	3.83	3.84
Installed zone substation capacity growth	2.25	2.20	2.09	2.30	0.00	3.75
Composite network growth	**2.16**	**2.30**	**2.36**	**2.49**	**1.75**	**2.97**

Source: JEN forecast data model; AER analysis.

Table J.8 SP AusNet revised proposal growth drivers (per cent)

	2010	2011	2012	2013	2014	2015
Customer number growth	**1.71**	**1.89**	**1.92**	**1.73**	**1.54**	**1.48**
Capex weighted line length, ZSS transformers and feeders growth		**2.45**	**2.45**	**2.45**	**2.45**	**2.45**

Source: SP AusNet, *Revised regulatory proposal*, p. 68; SP AusNet scale opex model.

Table J.9 United Energy revised proposal growth drivers (per cent)

	2010	2011	2012	2013	2014	2015
Customer number growth	**0.73**	**0.99**	**0.92**	**0.80**	**0.71**	**0.73**
Composite network growth driver						
Line length growth		0.97	0.96	0.95	0.94	1.36
Distribution transformer growth		2.99	2.71	2.66	2.59	2.55
Installed zone substation capacity growth		1.28	2.33	3.13	2.02	0.99
Composite network growth		**1.75**	**2.00**	**2.25**	**1.85**	**1.63**

Source: United Energy, *Revised regulatory proposal*, p. 82; AER analysis

The AER's consideration of the Victorian DNSPs' revised proposals and where they vary from the AER's draft decision is detailed below.

J.6.2.3 Submissions

The EUCV submitted that great care must be taken to ensure that any scaling factor (that is, growth driver) replicates the actual organic growth of the network occasioned by geographical expansion, and the impact of new replacement assets is reflected by a reduction of opex.[26]

The EUAA expressed a concern that the AER's adopted growth drivers do not adequately take opex increases due to customer density growth into consideration. The EUAA submitted this is especially important for those businesses whose regions will experience increasing customer density rather than extensions of the network.[27] The EUAA considers the AER ought to make adjustments where necessary to address the impact of customer density on opex.[28]

EnergyAustralia considered in its submission that the AER rejected the majority of the Victorian DNSPs' growth drivers and derived a substitute amount based on an equation that relates increases in opex to increases in line length and customer

[26] EUCV, *Submission to the AER*, August 2010, pp. 39–40.

[27] Energy Users Association of Australia (EUAA), *Submission to the AER - AER Draft Determination on Victorian electricity distribution prices for the period 2011-2015 and distributors revised proposals*,19 August 2010, p. 35.

[28] ibid

numbers.[29] EnergyAustralia also questioned why customer numbers would drive maintenance costs on new assets.[30] EnergyAustralia also submitted that the AER appears to be using data provided by EnergyAustralia.[31]

In relation to maintenance escalation, EnergyAustralia submitted that the AER should consider the cost of additional maintenance required as a result of new assets on the network, and maintenance requirements based on the condition of the asset base over the regulatory control period as drivers for future maintenance expenditure.[32]

J.6.2.4 Consultant review

In assessing the Victorian DNSPs' proposed growth rates, the AER engaged Nuttall Consulting to review and make recommendations on the AER's selection of growth drivers.[33] Nuttall Consulting assessed the appropriateness of the growth drivers proposed by CitiPower, Powercor, JEN and United Energy in their revised proposals.[34]

Nuttall Consulting considered that the selection of drivers is reasonable.[35] Nuttall Consulting noted that although each driver has advantages and disadvantages, the use of four proxy drivers improves the overall consistency of the drivers and reduces the impact of variability in any one driver.[36] Nuttall Consulting also confirmed that, based on the relationship between major asset classes and the selected drivers, the drivers provide good coverage of the overall network asset base.[37]

J.6.2.5 Issues and AER considerations

The AER acknowledges the EUCV's concern and notes that the AER's approach cannot replicate actual organic growth because it is based on the assumption that growth in key distribution assets and customer numbers can be used as a proxy for actual network growth. The AER considers that growth in network assets and customer numbers is representative of actual network growth. The AER therefore considers its selection of growth drivers, discussed below, results in forecast opex that reasonably reflects a realistic expectation of the demand forecasts and cost inputs required to meet or manage the expected demand for standard control services.[38] The AER also notes that not all growth will necessarily result in geographical expansion, particularly in urban networks.

The AER notes that EnergyAustralia's comments in relation to the AER's growth drivers are incorrect. In the draft decision, the AER applied two growth drivers (customer number growth and network growth) not an equation that relates increases in opex to increases in line length and customer numbers, as EnergyAustralia has suggested. The composite network growth driver included line length, but also

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29 EnergyAustralia, *Submission to the AER*, p. 12.
30 ibid., p. 13.
31 ibid., p. 12.
32 ibid.
33 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010.
34 Customer numbers, line length, distribution transformers and zone substation capacity.
35 ibid., p. 4.
36 ibid.
37 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010, p. 5.
38 NER, cll. 6.5.6(e)(1), 6.5.6(a)(1).

included the number of distribution transformers and the number of zone substations. Line length and zone substation numbers were proposed by SP AusNet.

In this final decision, the AER has maintained the customer number and composite network growth drivers, but has modified the network growth driver, substituting growth in the number of zone substations with growth in the capacity of zone substations. This change is based on the South Australian distribution determination and the revised proposals of four of the Victorian DNSPs and is explained further below. Further, the AER has not used customer numbers as a driver for maintenance costs on new assets in either the draft decision or this final decision, nor has it used any data provided by EnergyAustralia for the Victorian DNSPs' growth drivers.

In response to EnergyAustralia's submission on maintenance drivers, the AER does not consider such granular drivers are appropriate. As noted above, the AER's approach to maintenance cost escalation is to use growth in core distribution assets as proxies for growth in network activities and volumes to estimate increases in forecast maintenance expenditure. The AER considers this is more appropriate than the maintenance costs of these assets. This is based on the premise that the relative size of the network has a direct impact on maintenance expenditure; an approach generally supported by the Victorian DNSPs.[39]

For the same reason, the AER does not consider that the condition of the asset base is relevant in determining future growth in the distribution network—a position also supported by Nuttall Consulting.[40] The AER also notes that maintenance requirements and the impact of new replacement assets are taken into account when determining adjustments for economies of scale (discussed in section J.6.6).

Growth in zone substation capacity

As noted above, CitiPower, Powercor, JEN and United Energy submitted that zone substation capacity was a better indicator of growth in operating and maintenance activity levels than growth in the number of zone substations.[41]

In its draft decision the AER noted that the Victorian DNSPs provided ten varying growth drivers and SP AusNet was the only DNSP to propose zone substation growth. Specifically SP AusNet proposed growth in the number and not capacity of zone substations.[42]

Recognising that PB, in advising the AER for the SA electricity distribution price review, recommended a composite growth driver including growth in zone substation capacity, the AER, in the draft decision, stated that it would consider alternatives such

39 The revised proposals of all the Victorian DNSPs except United Energy contained scale escalation forecasts based on growth in key distribution assets. See for example, CitiPower, *Revised regulatory proposal*, p. 221; Powercor, *Revised regulatory proposal*, p. 209; JEN, *Revised regulatory proposal*, p.119; SP AusNet, *Revised regulatory proposal*, p. 195.

40 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review,* September 2010, p. 5.

41 CitiPower, *Revised regulatory proposal*, pp. 221–222; Powercor, *Revised regulatory proposal*, pp. 209–210; JEN, *Revised regulatory proposal*, pp. 120–121; United Energy, *Revised regulatory proposal*, pp. 82–83

42 See table J.5 of appendix J of the draft decision

as installed zone substation capacity where the Victorian DNSPs provide adequate justification for such an alternative.[43]

In response to the AER's draft decision, CitiPower and Powercor engaged PB, who noted:[44]

> The use of the number of zone substations is likely to be a less accurate indicator of growth in opex costs than aggregate capacity as typically, operational costs, inspection costs and routine/condition/emergency related maintenance is undertaken based on both the number of discrete pieces of plant and equipment used within zone substations, and to a lesser extent the size (which may be considered a measure of the importance of the plant). Periodically, it is reasonable to expect a zone substation with four transformers and associated volumes of sub-transmission and HV switchgear will require substantially more operation and maintenance opex compared with a single transformer site.

In recent advice to the AER, Nuttall Consulting confirmed that zone substation capacity is more appropriate than the number of zone substations, noting that:[45]

> The number of zone substations in each DNSP is relatively small. Thus, the use of a "number of zone substations" measure would be inappropriate due to the large increment/change that would result from each additional zone substation.

However, Nuttall Consulting also noted a number of caveats with zone substation capacity:[46]

- the definition of capacity has become more problematic over time as DNSPs have moved to adopt winter and summer capacity limits and are moving to dynamic capacity management
- some of the infrastructure associated with zone substations, such as enclosures and earthing, are required irrespective of the capacity of the zone substation, whereas other infrastructure, such as protection and switchgear, is more proportional to capacity
- the capacity increase associated with a single zone substation will result in larger incremental changes than to the other drivers
- the honeymoon period (reduced operating expenditure requirements associated with new assets) applies to the majority of zone substation assets.

Despite these caveats, Nuttall Consulting did not recommend any other driver as any more appropriate.[47]

43 See footnote 47 of appendix J of the draft decision

44 CitiPower, *Revised regulatory proposal*, p. 222; Powercor, *Revised regulatory proposal*, p. 209.

45 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review,* September 2010, p. 14.

46 ibid., pp. 14–15.

47 ibid., p. 14.

As a result of the Victorian DNSPs' revised proposals and Nuttall Consulting's recommendations, the AER considers that zone substation capacity is a more appropriate proxy than the number of zone substations. The AER considers this change is consistent with total forecast levels of opex that reasonably reflect a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services[48] because it better reflects the variation in operating and maintenance activity levels, particularly for higher density urban growth areas. The AER also considers that growth in zone substation capacity as a driver addresses the EUAA's concern that the AER's draft decision growth drivers did not adequately take customer density growth into consideration.

Growth in the number of power transformers and distribution feeders

In its revised regulatory proposal, SP AusNet proposed to substitute growth in the number of distribution transformers and zone substations with growth in feeders and power transformer population.[49] Although not explicitly mentioned in its revised proposal, SP AusNet maintained its position, consistent with the AER draft decision to apply growth in line length, albeit under the misguided belief that the AER's intention was to apply lagged line length as a growth driver in the draft decision.[50]

SP AusNet, in its initial regulatory proposal, applied the following network growth drivers:[51]

- change in lagged customer numbers
- change in line length
- change in overhead lagged line length
- change in underground lagged line length
- change in number of zone substations.

For the purpose of the draft decision, the AER accepted SP AusNet's initial proposal regarding growth in line length and the number of zone substations. However, the AER was concerned with the accuracy of SP AusNet's forecast line length and applied historical growth in line length as a proxy for forecast growth in line length.

In its revised proposal, SP AusNet stated that:[52]

> SP AusNet has considered the proposals put to the AER by other DNSPs and has concluded that in fact it is inappropriate to use the number of zone sub stations as a key underlying driver of SP AusNet's opex costs. In particular, SP AusNet accepts the arguments put by other parties that this driver does not capture the impact that new equipment installed at existing sites will have on expected opex costs. This equipment is primarily driven by the need to provide additional capacity at those sites. A prime example of

48 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
49 SP AusNet, *Revised regulatory proposal*, p. 195.
50 ibid., p. 194.
51 See table J.5 of appendix J of the draft decision
52 SP AusNet, *Revised regulatory proposal*, p. 195.

> this is where additional transformers are installed at existing zone sub stations.

The AER notes that the comment above from SP AusNet's revised proposal reflects the intent of the revised proposals of CitiPower, Powercor and JEN, in that a growth driver reflective of incremental or modular asset growth at zone substations better reflects increases in customer density within urban growth areas.[53] Further, the AER notes that operating and maintenance activity levels associated with zone substations are more likely to vary with their capacity.

However, SP AusNet did not propose zone substation capacity, stating that the application of power transformer growth and feeder growth is intended to reflect the need to provide additional capacity at those sites.[54] As noted above, the AER considers that growth in zone substation capacity is consistent with the South Australian decision and the revised regulatory proposals of CitiPower, Powercor, JEN and United Energy and also reflects SP AusNet's view that opex is driven by capacity rather than the number of sites. Further, Nuttall Consulting considered the AER's chosen drivers map to the majority of network assets.[55]

On balance, the AER does not accept SP AusNet's proposal to use growth in feeders and power transformer population. The AER does not disagree in principle with SP AusNet's selection of power transformers and feeders as a growth driver, as they are representative of growth in capacity. However, the AER considers that SP AusNet's derivation of its driver based on power transformers and feeders means the growth rate proposed by SP AusNet is not consistent with part of a total opex forecast that reasonably reflects the realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[56]

Firstly, SP AusNet has applied an arbitrary weighting of 70 per cent for transformer growth and 30 per cent for feeder growth to create a single driver. SP AusNet states that this is reasonable because it reflects the higher per unit maintenance and condition monitoring requirements of transformers relative to switchgear,[57] but has not supported this statement by any calculations or analysis. Secondly, SP AusNet notes that:[58]

> the inclusion of transformers and feeders as a growth driver complicates the calculation of the underlying opex weighting, as SP AusNet does not capture data at this level.

Finally, the forecast growth rate for this driver (3.1 per cent) is substantially higher than the forecast growth in overall zone substation capacity taken from SP AusNet's RIN (2.2 per cent), and slightly higher than the historical growth rate (2.9 per cent).

Therefore the AER is not satisfied that SP AusNet's proposal to apply a driver based on power transformer and feeder growth is consistent with part of a total forecast opex

53 For example, JEN, *Revised regulatory proposal*, pp. 120–121.
54 ibid.
55 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010, p. 14.
56 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).
57 SP AusNet, *Revised regulatory proposal*, p. 195.
58 ibid.

that reasonably reflects the realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[59]

Growth in the number of distribution transformers

In its revised regulatory proposal, SP AusNet did not accept the AER's draft decision to include growth in the number of distribution transformers. SP AusNet noted:[60]

> SP AusNet does not consider Distribution Transformer growth to be representative of opex growth due to the simple low maintenance nature of distribution transformers, which are in the main, operated on a run to failure replacement strategy.

Nuttall Consulting commented that although this is true for most DNSPs and particularly rural businesses, a run to failure policy does not mean that opex is not incurred.[61]

Nuttall Consulting noted that SP AusNet inspects and monitors distribution transformers, and therefore incurs maintenance costs. Nuttall Consulting further noted that:[62]

> - All DNSPs inspect (at least visually) pole-mounted transformers as part of the pole inspection programs.
>
> - The switchgear and protections systems of a distribution transmission also require inspection and maintenance.
>
> - Emergency maintenance is undertaken on distribution transformers and associated assets – possibly in greater proportions than other assets due to the run to failure policy.

In any case, the AER's approach to scale escalation is based on the assumption that the growth rate in distribution transformers is an appropriate driver of the network growth opex, not the nature of the maintenance requirements of the assets. Therefore, in terms of the actual impact on a DNSP's opex allowance, the 'simple low maintenance nature' of the transformer does not impact the growth rate. Specifically, the AER considers that the growth in the number of distribution transformers provides a proxy for growth in the physical size of the distribution network, and when combined with line length and zone substation capacity, provides for a cross-section of growth in the area serviced, and increased customer density. The actual maintenance cost of specific asset components is of less importance.

The opex allowance is based on the level of growth in physical assets to be maintained because (as mentioned earlier) the AER considers this approach is

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59 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).

60 SP AusNet, *Revised regulatory proposal*, p. 194.

61 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review,* September 2010, p. 12. Nuttall Consulting commented that SP AusNet (amongst other things) inspects distribution transformer condition at five-year intervals and monitors operating temperatures, partial discharge emissions and dissolved gasses of three-phase transformers commensurate with electrical utilisation and consequences of failure.

62 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review,* September 2010, p. 13.

representative of how the distribution network will actually grow, and is an approach generally supported by the DNSPs.[63] As such the AER considers this is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[64] The fact that CitiPower, Powercor and JEN accepted the approach of the AER to apply growth in the number of distribution transformers in calculating the composite network growth driver further supports the AER's position. In addition, SP AusNet did not provide any evidence to suggest that growth in distribution transformers is not an appropriate proxy other than the view expressed above.

Growth in line length

None of the Victorian DNSPs disputed the AER's application of line length as a growth driver.[65] Nuttall Consulting also supported the use of line length as a growth driver, noting that:[66]

- electricity lines and the associated assets represent the largest group of assets in a DNSP's RAB
- is information that the Victorian DNSPs have collected and reported for many years, and is a common reporting measure in DNSP annual reports
- line length is also used as a growth driver in the UK.

The AER therefore maintains its view from the draft decision that growth in line length is an appropriate growth driver for use in the final decision. Nuttall Consulting's advice suggests line length as a growth driver aligns very strongly to physical growth in a distribution network. On this basis, the AER considers that the application of growth in line length as a driver for scale escalation reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[67]

Growth in customer numbers

Each of the Victorian DNSPs applied the rate of change in customer numbers as a growth driver in their revised regulatory proposals. Nuttall Consulting also supported the use of growth in customer numbers, noting that the historical use and consistent definitions of this driver suggest it is valuable as a proxy for growth in opex. Nuttall Consulting further noted that although growth in customer numbers is not directly attributable to assets and asset related opex (and would therefore not be an appropriate

63 CitiPower, *Revised regulatory proposal*, p. 221; Powercor, *Revised regulatory proposal*, p. 209; JEN, *Revised regulatory proposal*, p.119; SP AusNet, *Revised regulatory proposal*, p. 195.

64 NER, cll. 6.5.6(c)(3), 6.5.6(a)(2)

65 Although United Energy did not propose increased opex based on scale escalation given that is has proposed a new business model for the forthcoming regulatory control period which incorporates changes in opex costs, United Energy submitted growth driver data as part of its revised proposal, including line length.

66 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review,* September 2010, pp. 11, 15.

67 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)

driver of maintenance expenditure), it is a better proxy for overheads and non-direct opex (including IT opex) than the drivers based on growth in network assets.[68]

The AER maintains its view from the draft decision that growth in customer numbers is an appropriate growth driver for use in the final decision on the basis that Nuttall Consulting's advice suggests that growth in customer numbers is closely related to an increase in operating costs. The AER therefore considers that the application of growth in customer numbers as a driver for scale escalation reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[69]

JEN IT scale escalation

In its revised regulatory proposal JEN submitted that:[70]

> The AER's proposed scale escalator is not relevant to determining growth in IT opex. JEN's proposed IT opex scale escalation factor is more relevant because line length, distribution transformers, zone substations and even electricity demand do not directly determine demand for IT services and systems.

In the draft decision, the AER allocated growth in customer numbers to all of the categories of operating expenditure in the RIN except for 'network operating' and 'other network operating'. The AER applied the composite network growth driver to these RIN categories, and to all of the RIN maintenance expenditure categories.[71] Upon review of the expenditure categories in the ESCV's *Electricity Industry Guideline No. 3*, (which is what the AER's RIN categories are based on) the AER considers that the 'network operating' and 'other network operating' RIN categories are not aligned with growth in network assets because they comprise the corporate costs of administering and running the network rather than maintaining it.[72] The AER considers that growth in customer numbers is more appropriate and therefore is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services[73] because growth in customer numbers tends to align with increased corporate overheads and running costs. This is discussed further in section J.6.5.

According to *Guideline No. 3*, IT opex tends to be categorised as either 'network operating' or 'other network operating'. As a result, the AER agrees that the draft decision allocation of the composite network growth driver to these categories is inappropriate considering that IT opex is more associated with operating the network rather than maintaining it. This view is also supported by Nuttall Consulting who note that network asset based scale drivers have a relatively poor alignment with IT assets compared to customer numbers.[74]

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68 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 2.
69 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
70 JEN, *Revised regulatory proposal*, p. 121.
71 See table J.7 of appendix J of the draft decision.
72 ESCV, *Electricity Industry Guideline No. 3–Issue No. 7*, May 2010, pp. 46, 51.
73 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
74 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010, p. 5.

JEN's revised regulatory proposal points to a number of drivers that it suggests warrants a growth rate above the rate provided in the AER's draft decision for its IT services and systems demand:[75]

- customer growth
- the number of meter reads per customer category and all associated meter records
- the number of transactions with the customer
- the number of interactions by customers with staff using the many technologies
- the number of outages per customer and geographic area
- records required to be retained by regulation as a minimum of 6 years and up to 25 years or the life of an asset
- the accumulation of data over time that builds up even though customers and transactions may be stable from one year to the next; this stand still rate is typically 4 per cent when population and general customer growth averages 1.8 per cent to 2 per cent due to data accumulation and increasing use of information technology

The growth drivers presented by JEN above relate primarily to growth in customer numbers. JEN has not substantiated on what basis meter reading services, outages, the number of transactions and customer interactions will increase at a greater rate than growth in the number of customers, or why this combination of drivers is more relevant to determining growth in IT opex. The AER notes that none of the other DNSPs proposed a separate growth rate for IT opex.

Therefore, in consideration of JEN's revised proposal, and noting the reasoning above, in this final decision, the AER has allocated growth in customer numbers to the 'network operating' and 'other network operating' RIN categories (and hence IT opex), but has rejected JEN's proposed IT opex scale factor. For the reasons above, the AER considers that the allocation of growth in customer numbers to IT opex satisfies JEN's concerns, and is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[76]

However, the AER acknowledges that JEN proposed a negative step change relating to its 'IT efficiency factor', which the AER accepted in its draft decision. JEN considers that the AER's decision to deduct the IT efficiency factor and reject the IT opex scale escalation factor is erroneous because it:[77]

> double deducts economies of scale as regards IT and capex-opex trade-off without providing JEN suitable recovery of its forecast IT opex.

The AER agrees that rejecting JEN's IT scale escalation and accepting JEN's IT efficiency factor step change amounts to a double deduction. Accordingly, the AER

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75 JEN, *Revised regulatory proposal*, p. 121.
76 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
77 JEN, *Revised regulatory proposal*, p. 121.

has removed JEN's IT efficiency factor step change. Step changes are examined in appendix L.

J.6.2.6 Conclusion on selection of growth drivers

The AER notes that growth drivers have been selected on the basis that they are representative of growth in the area serviced by a DNSP and growth in customer density. The rate of growth for each of these drivers varies between DNSPs because customer growth rates, the location of growth (for example, green-field and brown-field sites) and the nature of the network (for example, rural and urban networks), are different for each DNSP. The AER considers that this approach is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required by each DNSP to achieve the opex objectives as required by clause 6.5.6(c)(3) of the NER.

The reason is that a composite growth factor based on the physical network assets of line length, the number of distribution transformers and zone substation capacity should result in forecasts of opex that most closely reflect the actual growth in maintenance activity levels because growth in the level of maintenance of assets is commensurate with growth in the assets themselves. Further, the use of a customer number growth driver should result in forecasts of opex that most closely reflect the actual growth in operating activity levels because as the customer base of a network increases, the cost of operating and administering the network should also increase.

These conclusions are also supported by Nuttall Consulting,[78] are largely consistent with AER’s approach in the ETSA utilities review[79] and are reflected in the trend analysis presented in section J.6.9.

As a result, for the reasons outlined above, the AER accepts the revised proposals of CitiPower, Powercor, JEN and United Energy to apply zone substation capacity in place of growth in the number of zone substations. However, the AER does not accept SP AusNet's revised proposal to adopt growth in the number of power transformers and distribution feeders, or JEN's proposal to adopt a separate driver for IT opex.

For the final decision, the AER has therefore adopted two growth drivers for each Victorian DNSP:

- a composite network growth driver calculated as the average of the annual growth in line length, the number of distribution transformers, and zone substation capacity over the forthcoming regulatory control period;
- the annual growth in customer numbers over the forthcoming regulatory control period.

[78] Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010; Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010.
[79] Noting that in the ETSA decision, a weighted average based on capital value was applied. AER, ETSA, *Final distribution determination 2010–2015*, p. 120.

J.6.3 Method for calculating composite network growth driver

J.6.3.1 AER draft decision

In the draft decision, the AER applied a simple average in the calculation of the composite network growth driver and observed:

> The resultant network growth rates can be supported intuitively as SP AusNet and Powercor, with large rural networks and relatively high customer growth rates, have higher network growth rates for scale purposes compared to CitiPower, [JEN] and United Energy. Similarly, CitiPower, with its closed urban network has the smallest network growth rate. [80]

J.6.3.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor and JEN accepted the AER's approach to apply a simple average to the weighting of the factors contributing to the composite network growth driver.[81]

SP AusNet proposed a weighted average based on the forecast capex of the respective growth drivers derived from its RIN.[82] SP AusNet submitted that its weighting is designed to reflect the higher per unit maintenance and condition monitoring requirements of transformers relative to switchgear.[83]

United Energy disagreed with the AER's decision to adopt a simple average and pointed to the AER's 2010–15 SA distribution determination:[84]

> The AER considers the use of a weighted average will provide a stronger reflection of the proportion of future opex requirements compared with assuming equal weighting across three asset classes.

SP AusNet also disputed the AER's use of a simple average when rejecting the use of distribution transformers as a growth driver:[85]

> This issue is magnified as the AER uses a simple average as the inclusion of Distribution Transformer growth reduces the overall composite network growth driver for SP AusNet. Ceteris paribus, this results in the scale escalation factor underestimating the true impact of network growth on SP AusNet's operating costs, which is inconsistent with the requirements of clause 6.5.6 (c) of the NER.

J.6.3.3 Consultant review

In assessing the Victorian DNSPs' proposed growth rates, the AER engaged Nuttall Consulting to review and make recommendations on the AER's method for weighting the growth drivers. Nuttall Consulting considered that intuitively, it seems reasonable to provide some sort of weighting system for the proxy elements because there are significant scale differences (for both volume and value) in the assets that contribute to line length, distribution transformer numbers and zone substation capacity.[86]

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80 Appendix J of the draft decision, p. 97.

81 CitiPower, *Revised regulatory proposal*, p. 221; Powercor, *Revised regulatory proposal*, p. 208; JEN, *Revised regulatory proposal*, p. 119.

82 SP AusNet, *Revised regulatory proposal*, p. 195.

83 SP AusNet, *Revised regulatory proposal*, p. 195.

84 United Energy, Revised regulatory proposal, p. 82.

85 SP AusNet, *Revised regulatory proposal*, p. 194.

86 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 1.

Nuttall Consulting also noted that future requirements imposed on the Victorian DNSPs such as AMI, SWER replacement and line clearance regulations could impact the relationship between the growth drivers, and subsequently the appropriateness of the weighting.[87] However, Nuttall Consulting considered that SP AusNet's proposal for a weighting based on forecast capex spend was not appropriate because this would result in significant changes to the weightings between periods due to the fluctuations inherent in capex.[88]

Nuttall Consulting noted that a weighting based on asset value would be more appropriate, but that it would require a reasonably detailed set of data and further analysis to accurately determine the whole-of-life opex attributable to each asset group or class because RAB value is not directly reflective of attributable opex.[89]

Nuttall Consulting considered that a simple average may be appropriate given the network growth composite driver is intended for use as a proxy, not a forecasting model, and it would also provide some certainty for DNSP forecasting.[90]

J.6.3.4 Issues and AER considerations

As discussed in section J.6.2.5, the comment by SP AusNet that the maintenance characteristics of distribution transformers means the inclusion of distribution transformers in the network growth driver underestimates the true impact on opex, is inaccurate.[91] For the reasons discussed below, the AER considers the statement that this issue is magnified by the use of a simple average, is also inaccurate.[92]

The AER considers that the use of line length, distribution transformers and zone substation capacity captures network growth driven by area and customer density. The AER acknowledges that a simple average could skew the composite growth rate where the outlying growth rates (either positive or negative) do not reflect the underlying assets' (that is, lines, transformers and zone substations) proportion of the network. That said, the AER also agrees with Nuttall Consulting that the use of four proxy drivers improves the overall consistency of the drivers and reduces the impact of variability in any one driver.[93]

In addition, SP AusNet's proposal to use forecast capex as the mechanism for weighting the drivers may also distort the assignment of growth rates from period to period, depending upon the age, condition and performance of the assets at any particular time. As a result, the variability in capex is unlikely to reflect the more stable nature of asset related opex. The information provided by SP AusNet did not sufficiently justify that its approach of using forecast capex would result in a weighting that is reflective of the realistic expectation of cost inputs for each DNSP.[94]

87 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010, p. 15.
88 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 1.
89 ibid.
90 ibid.
91 SP AusNet, *Revised regulatory proposal*, p. 194.
92 ibid.
93 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 4.
94 NER, cl. 6.5.6(c)(3).

In fact, SP AusNet's revised proposal infers that SP AusNet's preferred approach is actually to weight the growth drivers by 2009 operating and maintenance costs, as it did in its initial scale model.[95] However, the inclusion of a growth driver based on power transformers and feeders means this approach is no longer possible due to the absence of detailed opex data, so SP AusNet has used forecast capex as a proxy.[96] The AER is therefore not satisfied that SP AusNet's approach of weighting by forecast capex is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[97]

United Energy also disputed the AER's methodology, but did not provide any suggestions as to an appropriate weighting other than noting that a weighted average was used in the ETSA decision.[98]

The AER acknowledges that the approach taken in the 2010–15 South Australian final distribution determination was to apply a weighted average based on capital value for the financial year ending 2008. The AER notes that there may be merit in weighting asset classes or components by the proportion of assets within the regulatory asset base. The initial allocation could reasonably be made using the replacement value or some other capital value, as in the South Australian final distribution determination. However, in further considering this matter in this review, the AER notes that the growth rates employed in scale escalation are intended to reflect the growth in physical assets (that is, activities and volumes) and not the growth in the capital value of those assets, which may incorporate growth in real prices, as noted by the AER in the draft decision.[99] Accordingly, a weighting based on capital value may not be commensurate with growth drivers based on physical assets.

The AER notes that other factors could also impact on the desired weighting of network growth drivers. For example, in relation to line length, Nuttall Consulting considered that future requirements imposed on the Victorian DNSPs such as SWER replacement and vegetation clearance may be significant in the forthcoming regulatory control period.[100] Nuttall Consulting noted that these programs may result in reduced opex for line length related assets.[101] Notwithstanding this, Nuttall Consulting considered it may be appropriate to increase the weighting for growth line length because it is accepted in Australia and the UK as a statistically relevant proxy for operating expenditure growth.[102]

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95 SP AusNet, *Revised regulatory proposal,* p. 195.
96 ibid.
97 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
98 United Energy, *Revised regulatory proposal*, p. 82.
99 See appendix J of the draft decision, p. 90.
100 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010, pp. 11–12.
101 ibid.
102 ibid., pp. 3, 15. See Wilson Cook, *Review of proposed expenditure of ACT & New South Wales electricity DNSPs: Energy Australia's submissions of January and February 2009, a report prepared for the AER*, 31 March 2009, p. 14; Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper, Ref: 47a/09*, 8 May 2009.

In relation to distribution transformers, Nuttall Consulting noted that the AMI rollout may alter their relationship with opex because the AMI data will remove the costs associated with installing physical meters on substations for testing and load analysis. Furthermore, AMI information may also lead to better replacement strategies and reduced fault and emergency work associated with distribution transformers.[103] Accordingly, Nuttall Consulting considered distribution transformers could be given a lesser weighting in the composite network driver.[104] In addition, Nuttall Consulting noted in relation to zone substation capacity as a driver that the capacity increase associated with a single zone substation will result in larger incremental changes than the other drivers, which may suggest it should be given a lower weighting.[105]

Based on Nuttall Consulting's analysis, and previous regulatory practice, the AER agrees there may be merit in adopting a weighted average for the composite network growth driver. However, the AER considers that a reasonably detailed set of data and further analysis is required to determine an appropriate approach to the weighting that is likely to deliver benefits beyond that provided by a simple average. The AER is not satisfied that the data currently available will provide a weighting for the forthcoming regulatory control period that reasonably reflects the realistic expectation of demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[106]

In conclusion, as noted earlier, CitiPower, Powercor and JEN support the use of a simple average. In addition, the AER notes Nuttall Consulting's view that the use of a simple weighting provides a mechanism that is easier to replicate and provides the DNSPs with a degree of certainty in forecasting future revenue. In particular, SP AusNet's proposal to weight these drivers based on forecast capex, and other developments (such as SWER replacement, AMI and vegetation clearance) could result in significant changes in scale opex from period to period.

Accordingly, for the reasons above, the AER considers that on balance, for the purposes of this final decision, the application of a simple average of a diverse selection of drivers, and the associated growth rates is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required by each DNSP to meet or manage the expected demand for standard control services.[107]

J.6.4 Growth driver forecasts

J.6.4.1 AER draft decision

In the draft decision, the AER adopted a composite network growth driver comprising total line length, the number of zone substations and the number of distribution transformers and a customer growth rate driver.

The AER rejected some of the DNSPs' forecasts and substituted its own forecasts where the growth rates were not supported by the Victorian DNSPs' initial proposals,

[103] ibid., p. 13.
[104] ibid.
[105] ibid., p. 14.
[106] NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
[107] NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)

particularly where growth in customer numbers and specific network characteristics appeared to be inconsistent. For example, the AER did not accept SP AusNet's forecast growth in line length from its RIN (2.8 per cent) on the basis that the forecast was well in excess of:[108]

- its customer growth rate (1.6 per cent)
- the line length growth rate used in its own scale escalation model (0.4 per cent)
- Powercor's forecast growth rate (comparable rural network, 1.0 per cent).

The AER used the line length growth rate reported in SP AusNet's RIN for the period 2005 to 2010 (1.7 per cent) as a substitute for forecast line length over the forthcoming regulatory control period and noted that it would review SP AusNet's forecast growth rate for the final decision.[109]

The AER's growth rates determined for the draft decision are presented in Table J.10.

Table J.10 AER draft decision on growth drivers 2011-2015 (per cent, per annum)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Customer numbers	**1.6**	**1.7**	**1.4**	**1.6**	**0.7**
Line length (km)	0.7	1.0	1.4	1.7	1.0
Distribution transformers (number)	1.8	1.8	1.0	0.9	1.0
Zone substations (numbers)	0.0	1.4	0.6	1.8	0.9
Network growth composite	**0.9**	**1.4**	**1.0**	**1.5**	**1.0**

Source: adapted from table J.6 of appendix J of the draft decision

J.6.4.2 Victorian DNSP revised regulatory proposals

In response to the AER's draft decision, the Victorian DNSPs submitted revised growth driver forecasts, including zone substation capacity, which are displayed in Table J.11.

[108] AER, *Draft decision–Appendix J*, pp. 96–97.
[109] ibid.

Table J.11 **DNSP revised proposal gross growth drivers (per cent, per annum)**

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Customer numbers	**1.7**	**1.9**	**1.5**	**1.7**	**0.8**
Line length (km)	3.4	1.8	1.4	1.7	1.0
Distribution transformers (number)	1.8	1.8	3.7	NA	2.7
Zone substation capacity (MVA)	2.6	3.1	2.1	NA	1.9
Network growth composite	**2.6**	**2.2**	**2.4**	**2.5**	**1.9**

Source: AER analysis of the Victorian DNSPs' revised regulatory proposals and models.

J.6.4.3 Consultant review

In assessing the Victorian DNSPs' proposed growth rates, the AER engaged Nuttall Consulting to review and make recommendations on the DNSPs' composite growth driver forecasts As part of this review, Nuttall Consulting considered whether historical growth rates for each driver are an appropriate basis for estimating the growth rates for the 2011-15 regulatory control period. Nuttall Consulting reviewed the relationship between the opex RIN categories and scale drivers, and reviewed the drivers themselves and concluded that historical growth rates are appropriate.[110]

Nuttall Consulting noted that routine and condition based maintenance represent the largest operating expenditure categories for the Victorian DNSPs and observed:[111]

- condition based expenditures require a trigger event such as an observation from an inspection, test or completion of a number of duty cycles
- routine maintenance expenditures are directly related to asset volumes and are performed periodically, rather than dictated by condition.

Nuttall Consulting noted that for both routine and condition based maintenance, there is typically a honeymoon period following installation of new assets, where no maintenance is required. Nuttall Consulting also noted that routine maintenance expenditures are highly predictable based on historical levels and asset volumes.[112]

In relation to emergency maintenance, Nuttall Consulting noted:[113]

- the trigger event is asset failure, which typically occurs as the asset approaches the end of its useful life
- most network assets are long-life assets

[110] Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review,* September 2010, pp. 15–16.
[111] ibid., pp. 8–9.
[112] ibid.
[113] ibid., pp. 9–10.

- faults caused by environmental factors and third parties are not driven by network age, and while being sporadic and difficult to predict, on aggregate should be relatively consistent from period to period.

In relation to vegetation management expenditure, Nuttall Consulting observed that it is directly related to the line exposed to vegetation, although future lines are likely to be constructed to minimise vegetation costs. This may lead to a decline in the overall relationship between vegetation management expenditure and line length, but Nuttall Consulting does not consider any decline would be material.[114]

In relation to the drivers themselves, Nuttall Consulting noted that forecasting could be problematic because the Victorian DNSPs have either not forecast the figure historically, or have not forecast it accurately.[115] For each driver, Nuttall Consulting also considered that the honeymoon period associated with new assets was applicable.[116]

Nuttall Consulting therefore considered that historical growth rates will provide a more accurate representation of forecast expenditures than the Victorian DNSPs' forecast growth rates.[117]

J.6.4.4 Issues and AER considerations

Customer growth

The AER has accepted the Victorian DNSPs' revised proposal customer growth forecasts on the basis that the NIEIR forecasts reflect recent historical trends. Customer growth is discussed further in Chapter 5. The customer number volumes and forecast growth rate for each of the Victorian DNSPs is displayed in Table J.12.

Table J.12 Customer number volumes

	2010	2011	2012	2013	2014	2015	Growth
CitiPower	309,692	316,818	322,742	327,190	331,100	337,050	1.71%
Powercor	704,066	717,745	731,603	745,570	759,343	772,544	1.87%
JEN	307,168	313,164	318,616	323,161	327,188	331,669	1.55%
SP AusNet	622,091	633,847	646,034	657,240	667,352	677,204	1.71%
United Energy	624,480	630,635	636,421	641,506	646,067	650,752	0.83%

Source: Victorian DNSP revised proposals, AER analysis.

Composite network growth

In its assessment of the forecast opex in the Victorian DNSPs' building block proposals, the AER must have regard to the opex factors in clause 6.5.6(e) of the NER. Clause 6.5.6(e)(1) of the NER refers to the information included in or

114 ibid., p. 9.
115 ibid., pp. 11–14.
116 ibid.
117 ibid., p. 15

accompanying a building block proposal. If the AER is not satisfied that the forecast opex reflects the opex criteria, the AER must not accept the forecast[118], and provide a substitute forecast pursuant to clause 6.12.1(4)(ii) of the NER.

For the final decision, upon consideration of the Victorian DNSPs' revised proposals and accompanying information, the AER had concerns with the accuracy of the forecast data for the network growth drivers due to a general lack of explanation and justification for the forecasts. The AER therefore analysed historical and forecast data for each of the Victorian DNSPs. The AER had regard to this analysis in accordance with clause 6.5.6(e)(3) of the NER to determine whether it could be satisfied that the growth drivers proposed by the Victorian DNSPs would be consistent with of a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the meet or manage the expected demand for standard control services.[119] The AER analysed the Victorian DNSPs' historical and forecast data from their RINs (initial and revised), revised proposals, opex models, and responses to AER information requests for:

- Line length (km)
- Zone substation capacity (MVA)
- Distribution transformers (number)

Upon reviewing this information, the AER was not satisfied that the Victorian DNSPs' revised forecasts would be consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[120] The AER's conclusion is based on observed inconsistencies, not just between historical growth rates and forecast growth rates, but also between forecasts themselves. For example, SP AusNet's forecast growth rates for zone substation capacity varied between 1 per cent and 4.5 per cent depending on the source.[121] In several cases, forecast growth was significantly higher than historical growth.

In addition, the AER encountered gaps in the data provided by the businesses. For example, CitiPower, Powercor and JEN did not supply complete historical data for low voltage line length.[122] Similarly, SP AusNet did not provide forecast distribution

118 NER, cl. 6.5.6(d).
119 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
120 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1)
121 For example, SP AusNet's initial RIN projected a growth of 1.03%, its revised RIN projected 2.22%, and in response to an information request, the projection increased to 4.53%. Further examples include: the forecast growth rate for 2011-15 for CitiPower's revised RIN and model for line length was over three times greater than its initial RIN. Similarly, the growth in distribution transformers in JEN's revised model was more than three times the size of that received by the AER in an information request response in March 2010.
122 CitiPower & Powercor, Response to information requested on 13 September 2010, submitted on 16 September 2010; JEN, Response to information requested on 8 September 2010, submitted on 15 September 2010.

transformer numbers on the basis that they are not derived through a bottom up build, and stated that some of its historical numbers were also unreliable.[123]

As noted above, the AER accepts the revised proposals from CitiPower, Powercor, JEN and United Energy to substitute growth in zone substation capacity for growth in the number of zone substations. However, based on the AER's own observations and analysis of Nuttall Consulting's advice, the AER considers it appropriate to estimate forecast growth rates for the 2011-15 regulatory control period on the basis of historical growth rates for each component of the composite network growth driver for the following reasons:[124]

- the lack of DNSP experience in forecasting distribution transformer numbers and line length
- the historical inaccuracy in the DNSP forecasts of zone substation capacity
- the unexplained inconsistency between current and forecast driver growth amounts contained in the revised DNSP proposals; and
- the 'honeymoon period' of reduced operating expenditure requirements associated with new assets.

The analysis undertaken by the AER in accordance with clauses 6.5.6(e)(1) and (3) of the NER for each component of the composite network growth driver is discussed below.

Line length

SP AusNet and United Energy provided a data set from 2001 to 2009 in their revised RINs,[125] so the AER applied a historical growth rate for that period to derive the forecast growth rate for the 2011–15 regulatory control period. CitiPower, Powercor and JEN could not provide a complete set of low voltage line length data for some or all of this period[126], so the AER initially considered applying a growth rate based on high voltage line length data only. However, the growth rates for all three businesses based on this data may not have been representative of LV line length and were not consistent with SP AusNet and United Energy's line length growth rates. Having regard to this analysis, the AER considered that the absence of LV data for CitiPower, Powercor and JEN's line would not provide a growth rate that reasonably reflects a realistic expectation of the cost inputs required to meet or manage the expected demand for standard control services.[127] The AER considered a growth rate in line length based on an average of SP AusNet and United Energy's historical data would be the most appropriate substitute for CitiPower, Powercor and JEN.

[123] SP AusNet, Response to information requested on 3 March 2010, submitted on 10 March 2010; SP AusNet, Response to information requested on 13 August 2010, submitted on 17 August 2010.
[124] Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review,* September 2010, p. 15.
[125] Revised RIN, Aging Assets (6.2), Table 2.
[126] CitiPower & Powercor, Response to information requested on 13 September 2010, submitted on 16 September 2010; JEN, Response to information requested on 14 September 2010, submitted on 15 September 2010.
[127] NER, cll. 6,5,6(c)(3), 6.5.6(a)(1).

The AER's forecast line length volumes based on historical growth rates are displayed in Table J.13.

Table J.13 Line length volumes (km)

	2010	2011	2012	2013	2014	2015	Growth
CitiPower[a]	7,489	7,615	7,744	7,875	8,008	8,143	1.69%
Powercor[a]	83,926	85,343	86,784	88,250	89,740	91,256	1.69%
JEN[a]	5,996	6,097	6,200	6,305	6,411	6,520	1.69%
SP AusNet	48,967	50,203	51,470	52,769	54,100	55,466	2.52%
United Energy	12,833	12,943	13,053	13,164	13,277	13,390	0.85%

Source: Victorian DNSP revised RINs, responses to information requests, AER analysis.
[a]Average of SP AusNet and United Energy.

Distribution transformers

All of the Victorian DNSPs except United Energy[128] were able to provide some historical data for this driver, albeit only from 2004 for Powercor, and 2003 for the other DNSPs.[129] A historical growth rate was applied from the available data to derive the forecast growth rate for the 2011-15 regulatory control period. As noted above, some of SP AusNet's historical numbers were not reliable and were therefore discounted, with the result that the AER applied the same growth rate as the draft decision. For United Energy, the AER applied an average of the other DNSPs.

The AER's forecast distribution transformer volumes based on historical growth rates are displayed in Table J.14.

128 Although United Energy provided data based on the aging asset schedule in its RIN, the AER could not use this data as it does not take into account distribution transformers that have been decommissioned. United Energy, Response to information requested on 23 September 2010, submitted on 13 October 2010.

129 CitiPower & Powercor, Response to information requested on 3 March 2010, submitted on 17 March 2010; JEN, Response to information requested on 3 March 2010, submitted on 24 March 2010; SP AusNet, Response to information requested on 3 March 2010, submitted on 10 March 2010.

Table J.14 Distribution substation volumes (number)

	2010	2011	2012	2013	2014	2015	Growth
CitiPower	4,531	4,575	4,620	4,665	4,710	4,756	0.98%
Powercor	81,095	82,611	84,156	85,730	87,333	88,966	1.87%
JEN	5,729	5,811	5,894	5,979	6,065	6,151	1.43%
SP AusNet	54,776	55,272	55,772	56,278	56,787	57,302	0.91%
United Energy[a]	12,234	12,406	12,580	12,756	12,935	13,117	1.40%

Source: Responses to information requests, AER analysis.
[a]Average of other four DNSPs.

Zone substation capacity

All of the Victorian DNSPs provided historical data from 2001 for maximum capacity by zone substation in either their initial or revised RINs.[130] The AER was able to aggregate this data for 2001 to 2009 to derive the system wide maximum zone substation capacity. The AER notes that the inclusion of zone substation capacity has increased the composite growth rates for all businesses compared to the draft decision.

The AER's forecast zone substation capacity volumes based on historical growth rates are displayed in Table J.15.

Table J.15 Zone substation capacity volumes (MVA)

	2010	2011	2012	2013	2014	2015	Growth
CitiPower	2,458	2,482	2,506	2,530	2,555	2,580	0.97%
Powercor	3,221	3,278	3,335	3,393	3,452	3,512	1.74%
JEN	1,498	1,514	1,530	1,546	1,563	1,579	1.06%
SP AusNet	2,502	2,573	2,647	2,723	2,801	2,881	2.87%
United Energy	3,050	3,100	3,151	3,203	3,256	3,310	1.65%

Source: Victorian DNSP initial and revised RINs, AER analysis.

J.6.4.5 AER conclusion on growth driver forecasts

As a result, for the reasons outlined above, the AER considers that although the growth drivers proposed by the majority of the Victorian DNSPs are consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services, the DNSPs' forecasts are not.[131] As a result the AER does not accept the forecasts for those drivers.

130 RIN, Demand (6.3), Table 11; Revised RIN, Demand (6.3), Table 17.
131 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).

The AER's conclusion on growth drivers and growth rates for the final decision is presented in Table J.16 and Table J.17.

Table J.16 AER final conclusion on gross growth drivers (per cent, per annum)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Customer numbers	**1.7**	**1.9**	**1.6**	**1.7**	**0.8**
Line length (km)	1.7	1.7	1.7	2.5	0.9
Distribution transformers (number)	1.0	1.9	1.4	0.9	1.4
Zone substation capacity	1.0	1.7	1.1	2.9	1.6
Network growth composite	**1.2**	**1.8**	**1.4**	**2.1**	**1.3**

Source: AER analysis.

Table J.17 AER variation to Victorian DNSPs' proposed gross growth rates (per cent per annum)

	DNSP proposed gross growth rates	AER variation	AER gross growth rates[a]
CitiPower	2.3	–0.8	1.5
Powercor	2.3	–0.5	1.8
JEN	2.4	–0.9	1.5
SP AusNet	2.0	–0.1	1.9
United Energy	–	–	0.9

Source: AER analysis
[a]Average annual growth rate applying the AER growth drivers from Table J.16

The resultant network growth rates can still be supported intuitively with the inclusion of zone substation capacity instead of the number of zone substations. As in the draft decision, SP AusNet and Powercor have higher network growth rates due to large rural networks and relatively high customer growth rates compared to CitiPower, JEN and United Energy. United Energy's low overall growth is expected due to low customer growth rate and a high proportion of operating expenditure compared to maintenance expenditure.[132]

J.6.5 Allocation of growth drivers to operating and maintenance activities

J.6.5.1 AER draft decision

The AER acknowledged that opex is also driven by the number of customers in terms of customer service and associated corporate operating costs. In the draft decision, the

[132] United Energy's operating costs are almost four times as high as its maintenance costs, compared to CitiPower who has equal opex and maintenance costs.

AER allocated the composite network growth driver and customer numbers to the following RIN operating and maintenance categories.

Table J.18 AER draft decision on the allocation of growth drivers

Expenditure category	Growth driver
Operating expenditure	
Network operating costs	Network growth composite
Billing and revenue collection	Customer numbers
Customer service	Customer numbers
Advertising/marketing	Customer numbers
Regulatory costs	Customer numbers
Other network operating costs	Network growth composite
GSL payments	Customer numbers
Maintenance Expenditure	
Routine maintenance	Network growth composite
Condition based maintenance	Network growth composite
Emergency maintenance	Network growth composite
SCADA and network control	Network growth composite
Other maintenance	Network growth composite

J.6.5.2 Victorian DNSP revised proposals

As discussed in section J.6.2.5, in its revised regulatory proposal, JEN submitted:[133]

> The AER's proposed scale escalator is not relevant to determining growth in IT opex. JEN's proposed IT opex scale escalation factor is more relevant because line length, distribution transformers, zone substations and even electricity demand do not directly determine demand for IT services and systems.

JEN considered that IT opex was more likely to be driven by several other drivers, and proposed its own IT opex scale escalator. Most of the IT opex drivers proposed by JEN relate to customer numbers.[134]

J.6.5.3 Issues and AER considerations

In response to JEN's proposal, the AER has reviewed the ESCV's *Electricity Industry Guideline No. 3*. The AER's opex and maintenance RIN categories are based on the

133 JEN, *Revised regulatory proposal*, p. 121.
134 ibid. See also section J.6.2.5.

definitions and categories determined by the ESCV in accordance with this guideline. *Guideline No. 3* defines network operating costs as:[135]

> The operational costs associated with the operation of the network including, but not restricted to, the staffing of the control centre(s), operational switching personnel, outage planning personnel, provision of authorised network personnel, demand forecasting, procurement, logistics and stores, information technology (IT) costs directly attributable to network operation, insurance costs and land tax costs.
>
> Demand forecasting costs include labour, material and IT charges for the purposes of forecasting peak demand, energy growth and customer numbers in the Distribution Licence area, but do not include energy trading costs related to the wholesale purchase of electricity.

Guideline No. 3 defines other operating costs as:[136]

> This category comprises finance, human resources, information technology and other costs that are directly attributable to or caused by the provision of distribution services by the Distribution Business in accordance with its Distribution Licence.

Upon review of the above definitions, the AER considers that the 'network operating' and 'other network operating' RIN categories are not aligned with growth in network assets because they relate to the corporate costs of administering and running the network (including IT) rather than maintaining it. The AER considers that growth in customer numbers is more appropriate and is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services[137] because growth in customer numbers tends to align with increased corporate overheads and running costs.

The AER's final decision on the allocation of the composite network growth driver and the customer growth driver is presented in Table J.19 below:

Table J.19 AER conclusion on the allocation of growth drivers to operating and maintenance activities

For the reasons discussed above, the AER considers its allocation of growth drivers is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[138]

[135] ESCV, *Electricity Industry Guideline No. 3–Issue No. 7*, May 2010, p. 46.
[136] ibid., p. 51.
[137] NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).
[138] NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).

Expenditure category	Growth driver
Operating expenditure[139]	Customer numbers
Maintenance Expenditure	Network growth composite

The AER notes that despite simplifying the growth driver allocation to the operating and maintenance level, economies of scale factors continue to be applied at a detailed expenditure level where possible in this final decision. The AER's consideration of adjustments for economies of scale is discussed below.

J.6.6 Economies of scale adjustments

The second stage in the AER's assessment of the Victorian DNSPs' revised regulatory proposals is to establish what adjustments are required for efficiencies arising from economies of scale. The opex criterion that total forecast opex must reasonably reflect the efficient costs of achieving the opex objectives in clause 6.5.6(c)(1) of the NER is particularly relevant to this analysis.

J.6.6.1 AER draft decision

In the draft decision, the AER varied the proposals submitted by CitiPower, Powercor and SP AusNet.[140] United Energy and JEN did not propose any specific economies of scale adjustments.

The variations from the Victorian DNSPs' initial regulatory proposals adopted by the AER for the draft decision largely related to specific maintenance categories (for example, emergency and condition-based maintenance).[141]

The AER's revisions in the draft decision increased the economies of scale adjustments from 44.4 per cent (Victorian DNSP proposed average) to an average of 57.6 per cent (AER average). Given JEN and SP AusNet did not propose an economies of scale adjustment, the AER applied the AER average of 57.6 per cent in the draft decision.[142] This means that on average, the draft decision growth rates for the Victorian DNSPs after accounting for efficiencies arising from economies of scale were 57.6 per cent of the gross growth rates.

J.6.6.2 Victorian DNSP revised regulatory proposals

In response to the AER's draft decision on economies of scale adjustments, the Victorian DNSPs generally resubmitted their initial proposals. CitiPower and Powercor accepted some of the AER's variations to their proposed economies of scale adjustments, but largely maintained their initial positions.[143] That said, the AER notes that the majority of the economies of scale adjustments accepted by CitiPower and Powercor relate to alternative control services, and are therefore not explicitly

[139] GSL payments are not included as they are not subject to scale escalation, as discussed in chapter 15.
[140] See section J.5.2 of the draft decision
[141] See table J.9 of appendix J of the draft decision.
[142] The specific adjustments were made to each of the AER operating and maintenance RIN categories (see table J.10 of appendix J of the draft decision).
[143] CitiPower, *Revised regulatory proposal*, p. 223, Powercor, *Revised regulatory proposal*, p. 211.

included in CitiPower or Powercor's forecast operating expenditure (and hence not subject to scale escalation for standard control services) pursuant to clause 6.5.6(b)(2) of the NER.

SP AusNet did not accept the AER's adjustments, and resubmitted that a 5 per cent economies of scale adjustment be applied across all maintenance activities.[144] SP AusNet also stated that the adoption of a 100 per cent economies of scale factor (that is, no scale escalation) for operating activities was primarily based on the assumption that its proposed IT capex program would be accepted.[145] SP AusNet further stated that should the AER maintain its decision to reject SP AusNet's increase in its IT capex, the AER must adjust the scaling factor for operating costs.[146]

JEN included a conditional adjustment for both its general scale escalation and IT scale escalation factors. JEN submitted that:[147]

> It is unreasonable to assume JEN can access the economies of scale available to its asset management contractor JAM without paying a commercial margin, and to the extent the AER rejects this margin in the final decision, the economies of scale deduction should be set to zero.

The economies of scale adjustments and their impact on gross growth rates are contained in the Victorian DNSPs' revised proposals are detailed in Table J.20:

Table J.20 Victorian DNSP revised proposal on economies of scale (per cent, per annum)

	DNSP revised proposal gross growth rate	DNSP revised proposal economies of scale	DNSP revised proposal net growth rate
CitiPower	2.3	42.9	1.3
Powercor	2.3	32.3	1.5
JEN	2.4	57.6	1.0
SP AusNet	2.0	43.6	1.1
United Energy	–	–	0.8

Source: Victorian DNSPs' *Revised regulatory proposals*, RIN scale escalation worksheets, cost escalation models; AER analysis.

J.6.6.3 Submissions

EnergyAustralia expressed concerns relating to escalation for maintenance expenditure, including that the AER's approach does not adequately capture the increase in maintenance requirements resulting from the deteriorating condition of assets on the network.[148]

144 SP AusNet, *Revised regulatory proposal*, pp. 196–197.
145 ibid., p. 196.
146 ibid.
147 JEN, *Revised regulatory proposal*, p. 119.
148 EnergyAustralia, *Submission to the AER,* pp. 13–14.

J.6.6.4 Issues and AER considerations

In response to JEN's 'conditional' adjustment, the AER notes that the removal of a related party margin does not remove the incentive or prospect of JAM realising future unidentified efficiency savings over the forthcoming regulatory control period (and beyond under the EBSS). These unidentified efficiency gains are realised when a DNSP provides its services at a cost less than that provided for through the forecast opex allowance.

In the draft decision, the AER presented a trend analysis of actual opex between 2003 and 2008 to reveal the efficiency gains realised by the Victorian DNSPs over this same period.[149] The actual or realised efficiency gains include those that can be identified at the start of a process (for example, economies of scale efficiency gains) and those that cannot be identified (for example technological improvements). The analysis revealed an average annual reduction in opex of 2.4 per cent per annum.[150]

In the draft decision, the AER determined that on average, a growth rate net of economies of scale efficiency savings of 0.4 per cent per annum was appropriate. The AER noted that if the trend in actual opex is expected to continue (for example, the rate of technological change) then the future unidentified efficiency gains available to the Victorian DNSPs (for the draft decision) over the forthcoming regulatory control period amounted to 2.8 per cent per annum.[151]

The AER does not consider JEN's statement that the removal of related party margins reduces the scope and incentive of JAM to pursue future efficiency gains is substantiated. The analysis presented in section J.6.9 of this appendix reveals that the Victorian DNSPs have the scope to realise unidentified future efficiency gains of 2.5 per cent per annum should the trend in actual opex continue over the forthcoming regulatory control period.

The AER considers that establishing an efficient total forecast opex allowance as required under clause 6.5.6(c)(1) of the NER involves consideration of economies of scale savings (identified efficiency gains). This approach also provides sufficient scope and incentive for the Victorian DNSPs to pursue unidentified future efficiency gains (for example, driven by technological change) as required in accordance with clause 6.5.8 of the NER and section 7A(3) of the NEL.

In this final decision, the AER has rejected related party margins for all of the Victorian DNSPs. As discussed in chapter 6, the AER considers that efficiencies realised by a related party contractor should be shared with consumers after a period of time. While the sharing of the efficiencies between the service provider and the related party contractor (before they are passed on to customers) is a matter entirely up to JEN and its related party contractors to determine, the contractual arrangements between the parties should not affect the timing that the benefit from those efficiencies are passed on to customers, or the magnitude of the efficiencies that are shared with consumers. Accordingly, the AER does not accept JEN's condition that its economies of scale adjustment ought to be reduced to zero if related party margins are rejected.

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149 AER, *Draft decision, Appendix J,* pp. 109–112.
150 ibid.
151 ibid.

Consistent with the approach taken in the draft decision, the AER has substituted its own economies of scale adjustments pursuant to clause 6.12.1(4)(ii) of the NER given that JEN did not offer an alternative economies of scale adjustment. In the absence of any further information from JEN, and because JEN accepted this averaging approach in response to the draft decision[152], the AER has derived JEN's economies of scale factors from the averages of CitiPower, Powercor and SP AusNet. These are shown in 0 in section J.6.6.5.

United Energy proposed growth drivers but did not propose any economies of scale adjustments or submit an opex scale model because its opex forecast was not based on the roll forward model like the other Victorian DNSPs.[153] Consistent with the approach taken in the draft decision, the AER has therefore substituted its own economies of scale adjustments pursuant to clause 6.12.1(4)(ii) of the NER. In the absence of information from United Energy, the AER has derived United Energy's economies of scale factors from averages of CitiPower, Powercor and SP AusNet, consistent with the approach taken in the draft decision. These are shown in 0 in section J.6.6.5.

CitiPower and Powercor agreed with the AER's position in the draft decision to make variations to the following initial economies of scale proposals:[154]

- Emergency faults (meters)
- Meters, times switches & services maintenance
- Metering communications
- New connections
- Quality audits

CitiPower and Powercor contested the following variations:

- Emergency maintenance
- Overhead line maintenance and defect maintenance
- Salary expenditure
- Vegetation control, insulator washing and bushfire mitigation (Powercor only)

These are each discussed in detail further below.

152 Noting JEN's 'conditions' discussed earlier.

153 United Energy noted on page 81 of its revised regulatory proposal that it did not apply a scale escalation factor in the development of its opex forecast because the tender process for outsourced services addressed unit prices and volumes concurrently.

154 CitiPower, *Revised regulatory proposal*, p. 223, Powercor, *Revised regulatory proposal*, p. 211. As noted above, these relate to alternative control services (with the exception of new connections and quality audits) and are therefore not subject to scale escalation anyway.

In addition, the following variations were not accepted by CitiPower and Powercor, and not discussed in their revised proposals:

- Customer supply negotiations[155]
- Revenue – customer connections.[156]

The AER noted in the draft decision that activities undertaken to support new customers (as opposed to existing customers) will effectively be a substitute for activity already in the base year because it is not ongoing, and the growth rate of customer numbers is relatively constant. On this basis, the AER applied a 100 per cent economies of scale adjustment (that is, no scale escalation) to customer supply negotiations and revenue–customer connections.[157] CitiPower and Powercor have not adequately justified their disagreement with these variations in their revised proposals, other than maintaining that they are reasonable based on SKM's assessment.[158]

For CitiPower an Powercor's initial regulatory proposals, SKM determined the economies of scale factors for CitiPower and Powercor with reference to a previous approach used by ETSA, ElectraNet and other NSPs.[159] This approach applied a 50 per cent economies of scale adjustment to the high level category of 'customer growth–connections management'.[160] The AER considers based on information provided by CitiPower and Powercor that the 'customer supply negotiations' and 'revenue–customer connections' expenditure categories are both within this high level definition.[161] The AER has therefore applied a 50 per cent factor to these expenditure categories. In doing so, the AER has rejected SKM's application of a 5 per cent economies of scale factor for 'revenue–customer connections' as there does not appear to be any basis to support this, given the AER's comments above.

SP AusNet disagreed with all of the AER's economies of scale adjustments.[162] The AER's consideration of SP AusNet's position is included in the discussion below.

Emergency maintenance and condition based maintenance

In the draft decision, for *emergency maintenance* the AER increased CitiPower and Powercor's economies of scale factor from 5 per cent to 45 per cent (that is, resulting in a reduction in total growth from 95 per cent to 55 per cent) on the basis that emergency response not only includes outages from factors such as storms, animals

155 This category was proposed by both CitiPower and Powercor, but Powercor did not assign any expenditure to it, so it is only applicable to CitiPower.

156 CitiPower & Powercor note that this item relates to the opex portion of customer connections expenditure recovered through standard control services. Response to information requested on 18 January 2010, submitted on 22 January 2010, p. 4.

157 AER, Draft decision, Appendix J, p. 102.

158 CitiPower, *Revised regulatory proposal*, p. 223, Powercor, *Revised regulatory proposal*, p. 211.

159 SKM, *Scale Escalators Model Review for CitiPower and Powercor Australia—final report*, 24 November 2009, p. 11.

160 ibid.

161 'Customer supply negotiations' captures all costs related to the negotiation with customers to provide them with a budget estimate of costs and terms conditions for new or increased supply. 'Revenue-customer connections' captures all revenue and expenditure directly associated with non capital work performed for which customers will be charged under the Schedule of Fixed Charges and recoverable works of a non capital nature. CitiPower & Powercor, Response to information requested on 18 January 2010, submitted on 22 January 2010, pp. 3–4.

162 SP AusNet, *Revised regulatory proposal*, p. 197.

contacting live assets and vegetation contacting mains, but also from asset failures. This is consistent with the approach adopted by the AER (on the advice of PB) for the 2010–15 South Australian distribution determination.[163]

CitiPower and Powercor note in their revised proposals that in the 2010–15 South Australian distribution determination, the support of the decision on emergency maintenance was conditional on the AER accepting an opex 'age escalator'.[164] Given CitiPower and Powercor are not proposing an 'age escalator' they consider that the emergency response factor should be returned to 5 per cent on the basis that: [165]

- SKM, in advising CitiPower and Powercor in response to the draft decision, advise that CitiPower and Powercor's networks are aging
- assets such as distribution transformers and zone substation primary and secondary equipment typically exhibit the 'bathtub' failure profile, where early in their life they exhibit failure rates (and require emergency maintenance)
- assets repaired under warranty (early failures) do not mitigate the need for emergency maintenance opex.

SP AusNet also disagreed with the AER's adjustment to emergency maintenance on the basis that newly installed assets exhibit the bathtub effect.[166]

In the draft decision the AER for *condition based maintenance* increased CitiPower and Powercor's economies of scale adjustments for overhead line maintenance and pole defect maintenance from 5 per cent to 75 per cent, resulting in a reduction in total growth from 95 per cent to 25 per cent.

In response to the AER's draft decision, CitiPower noted that a significant volume of the work relates to routine asset inspections rather than asset failures. CitiPower stated that the programs involve preventative works to deal with 'defects' on the asset that, if not addressed, will cause the asset to fail in future.[167]

> As CitiPower's network grows, more poles, distribution transformers and zone substation equipment enter the maintenance system. As a consequence, more asset inspections and routine testing is scheduled.

SP AusNet submitted that:[168]

> ...the AER has not given reasonable regard to appropriate factors in making its decision on this issue; in particular, that is, the fact that many defects are caused by exogenous events.

In its submission, EnergyAustralia considered that the AER has erred in accepting that the majority of assets have a flat defect life, and consider that the defect rate will vary

[163] AER, *ETSA Utilities draft distribution determination*, October 2009, pp. 212–214, and not departed from in the final distribution determination.
[164] CitiPower, *Revised regulatory proposal*, p. 225, Powercor, *Revised regulatory proposal*, p. 213.
[165] CitiPower, *Revised regulatory proposal*, p. 226, Powercor, *Revised regulatory proposal*, p. 214.
[166] SP AusNet, *Revised regulatory proposal*, p 197.
[167] CitiPower, *Revised regulatory proposal*, p 226.
[168] SP AusNet, *Revised regulatory proposal*, p. 197.

with the type of asset and its physical condition. EnergyAustralia also notes Wilson Cook's observation that 'other things being equal, the level of maintenance expenditure needed on a network will increase as the network ages'.[169]

The AER agrees that defect rates in assets will vary depending on the circumstances of the asset, including its age, type, and condition. The AER also agrees that in general although an older network will require more maintenance, the converse also applies. That is, a newer network will require less maintenance. The AER therefore considers that as defective or aged assets are replaced, the relative age (and maintenance requirements) of the network should be relatively stable, or slightly increasing. This is supported by SP AusNet's comment that:[170]

> Despite "older assets being the focus of a well targeted, prioritised and optimised asset replacement program", assets that aren't currently in that 'replacement bracket' will move into that bracket during the next regulatory control period, thus offsetting the reduction in operating costs caused by replacing those older assets.

The AER further notes that its decision to remove the capex/opex trade-off adjustment (discussed in section J.6.7) is primarily based on arguments put forward by the Victorian DNSPs that maintaining asset and service performance may require an increase in RQM capex from historic levels (considering their aging asset bases). The result is that (assuming no network growth) the base year opex should be a reasonable approximation of the required level of opex to maintain the existing asset base, meaning that no downward adjustment should applied for a capex/opex trade-off.

The removal of the capex/opex trade-off adjustment means the impact of aging assets should therefore not be used as justification for applying lower economies of scale factors for an increased maintenance allowance due to growth. This is because the impact of aging assets would be used as the basis for an increased allowance twice: first as a result of the removal of the capex/opex trade-off, and second by way of a lower efficiency deduction. The AER does not consider that this outcome would be consistent with a total forecast opex that reasonably reflects the efficient costs of meeting or managing the expected demand for standard control services.[171]

In addition, analysis by Nuttall Consulting for the draft decision suggests that the percentage of old[172] assets in each of the Victorian DNSPs' asset bases is currently between 2.3 per cent and 3.5 per cent.[173] This suggests a low proportion of the Victorian DNSPs' assets will require maintenance simply because they are old. The AER has been unable substantiate the proportion of old assets forecast to be in the DNSPs' asset bases in 2015. As a result, the AER is not able to determine whether there will be either a reduction or an increase in opex associated with aging assets over the forthcoming regulatory control period. However, SP AusNet's comment above suggests such maintenance requirements should remain relatively stable.

169 EnergyAustralia, *Submission to the AER*, p. 14.
170 SP AusNet, *Revised regulatory proposal*, p. 199.
171 NER, cll. 6.5.6(c)(1), 6.5.6(a)(1).
172 90 per cent of the asset's life.
173 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, 4 June 2010, p. 38.

In relation to asset failure, the AER considered in the draft decision that the rate of failures or defects for new assets should, in general terms, be less than the rate of failure of older assets.[174]

By proposing 5 per cent economies of scale factors for emergency maintenance and condition based maintenance, CitiPower, Powercor and SP AusNet's revised proposals imply that newly installed assets are effectively equally as expensive to maintain as assets in the 'normal' part of their life-cycle.

CitiPower, Powercor and SP AusNet point to the bathtub curve for newly installed assets to support their proposals. In simple terms, the bathtub curve suggests that in addition to opex increasing as an asset ages, new assets may be subject to increase levels of emergency repair and restoration activity due to faulty components or installation problems.[175]

CitiPower, Powercor and SP AusNet also contend that routine asset inspections drive condition-based maintenance expenditure and of the defects identified, many are caused by exogenous events which also impact new assets. The AER acknowledges that network growth will lead to more routine asset inspections, and hence more condition based maintenance. The AER also recognises that routine and condition based maintenance tend to represent the largest operating expenditure categories for all DNSPs.[176] However, the AER also considers that the honeymoon period associated with new asset installation means that economies of scale can be realised for routine and condition based maintenance.[177] As a result, the AER considers that CitiPower, Powercor and SP AusNet's proposals of a 5 per cent economies of scale adjustment is unreasonable, but a reduction of the economies of scale factor from 75 per cent to 45 per cent is appropriate.

The AER considers that an economies of scale factor of 45 per cent applied to *emergency maintenance* remains reasonable and a reduction in the economies of scale factor for *condition-based maintenance* from 75 per cent to 45 per cent is also reasonable on the basis that:

- the increase in maintenance requirements following installation ('bathtub' curve) is likely to be offset by reductions in routine maintenance and inspections for new assets.[178] This is also supported by SKM in its scale escalation review for CitiPower and Powercor, who noted that replacing an aged asset with a new one should decrease the opex effort.[179]

174 AER, *Draft decision, Appendix J*, Table J.9.

175 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 4.

176 ibid., p. 8.

177 ibid., pp. 8–9.

178 New assets are often excluded from inspection and maintenance programs for a significant period of their early lives (for example, JAM commences inspection of all poles at 15 years). See United Energy, Regulatory proposal, Appendix E-1.15– Poles life cycle management plan (UE 4356-102), p. 8.

179 SKM, *Scale Escalators Model Review for CitiPower and Powercor Australia—final report*, 24 November 2009, p. 9.

- the reduced maintenance requirements associated with 'new assets' (growth and RQM capex) due to the honeymoon period is likely to offset increases in opex requirements caused by an aging network.

- notwithstanding the comments above, the AER's consideration of the impact on opex from an aging asset base is contained in the capex/opex trade-off discussion in section J.6.7. The remaining consideration is the maintenance requirements of new growth assets against existing assets. The AER does not consider it unreasonable to assume the maintenance requirements for new assets is less than existing or older assets.[180]

- although the AER recognises that emergency maintenance will be required as a result of exogenous events, these faults should be sporadic and difficult to predict, so on aggregate they typically represent a consistent trend and would be relatively consistent from period to period.[181]

- the AER's top down analysis indicates that actual opex activity levels for the Victorian DNSPs as a whole fell by 1.9 per cent per annum between 2003 and 2009[182]

For the reasons above, the AER considers that the AER's emergency and condition based maintenance adjustments are the minimum adjustment necessary to form part of a total forecast opex that reasonably reflects the efficient costs of meeting or managing the expected demand for standard control services as required by clauses 6.5.6(c)(1) and 6.5.6(a)(1) of the NER. The AER has had regard to the opex factors in clauses 6.5.6(e)(1) and (3) in making this decision.

Salary expenditure

CitiPower and Powercor did not accept the AER's variation to the economies of scale factor for salary expenditure in the draft decision (5 per cent to 100 per cent).[183]

In the draft decision, the AER was not satisfied that increases associated with salary expenditure are driven by increased opex activity levels and not real labour cost increases already captured within the forecast opex allowance.[184]

The AER acknowledges that the actual economies of scale factor used in determining scale escalation opex and in-turn the forecast opex allowance for CitiPower and Powercor was 75 per cent and not 100 per cent as indicated in table J.9 of appendix J of the draft decision. Nevertheless, the AER maintains that an increase in the economies of scale factor from 5 per cent to 75 per cent is warranted on the basis that

180 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 5.

181 Nuttall Consulting, *Opex Escalation Review–Victorian Electricity Distribution Revenue Review*, September 2010, pp. 9–10.

182 See section J.6.9.

183 CitiPower, *Revised regulatory proposal*, p. 227. Powercor, *Revised regulatory proposal*, p 215. It should be noted that CitiPower and Powercor's revised models apply an economies of scale adjustment of 75 per cent for salary expenditure.

184 See section J.6.9.

some or all of the real cost increases in salary expenditure will be captured by real cost escalators.[185]

CitiPower and Powercor submitted in their revised regulatory proposals that the function code is applied only to salaries earned in the network business unit who do not allocate their time by project. Activities undertaken include control and operations and inspection and maintenance.[186]

The AER accepts that salary costs will rise as customers are added to an expanding network because the workforce will also grow. However, the AER does not accept that activity levels associated with salary costs will increase at 95 per cent of the growth rate on the basis that CitiPower and Powercor did not directly address the AER's concern that increases in salary costs will also be driven by real increases in labour costs.

Therefore, the AER retains its view to apply an economies of scale adjustment of 75 per cent for the final decision because the remaining cost should be captured by real cost escalation.[187] The AER therefore considers that an economies of scale factor of 75 per cent for salary expenditure for CitiPower and Powercor is consistent with a total forecast opex that to reasonably reflects clause 6.5.6(c)(3) of the NER because it is reflects a more realistic expectation of the cost inputs required to meet or manage the expected demand for standard control services.[188]

Vegetation control, insulator washing and bushfire mitigation

In the draft decision, the AER adjusted Powercor's economies of scale factors for vegetation control, insulator washing and bushfire mitigation from 5 per cent to 75 per cent. The basis for the adjustment was that SKM, engaged by CitiPower and Powercor, recommended the adjustment be made on account of growth occurring within the existing network. However, the AER acknowledges that the variations recommended by SKM were to be made to CitiPower only.[189]

In considering the issue of vegetation control in the draft decision, the AER noted:[190]

> Interruptions resulting from vegetation are less likely to occur within new growth areas as vegetation, where it is pre-existing, is generally cleared before the network is built.

The AER notes that most DNSPs require landowners to establish a clearance zone for new overhead electrical lines on their properties.[191] Developers who establish industrial, commercial or residential developments are also required to clear vegetation away from any overhead lines within the development (if not placed underground). In addition, when planning construction of a new power line, DNSPs

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185 AER, *Draft decision, Appendix J*, pp. 101–102.
186 CitiPower, *Revised regulatory proposal*, p. 227. Powercor, *Revised regulatory proposal*, p 215.
187 See table J.18.
188 NER, cl. 6.5.6(a)(1).
189 SKM, *Scale Escalators Model Review for CitiPower and Powercor Australia—final report*, 24 November 2009, p. 11.
190 Footnote 58 of appendix J of the draft decision
191 Powercor, *Requirements for new powerlines - vegetation clearing*, March 2007 and Western Power, *Application for supply extension scheme*, 14 March 2007 (referred to in Nuttall Consulting, *Advice to the AER on Opex Scale Escalation,* 29 July 2010, p. 7)

will typically ensure that the route of the line avoids unnecessary and recurrent clearing and pruning of remnant vegetation, and where practicable, vegetation species suitable for growing near the powerlines are not removed.[192]

In addition, new lines in CBD and urban areas are becoming progressively harder to construct overhead due to community expectations and clearance requirements. The majority of these lines are now constructed underground.[193]

The AER acknowledges that new legislative or regulatory obligations such as the *Electricity Safety (Electric Line Clearance) Regulations 2010* may impose additional vegetation management and bushfire mitigation requirements on the Victorian DNSPs. Expenditure arising from regulatory obligations or changes in a DNSP's operating environment on clearance zones and bushfire mitigation is dealt with under opex step changes (see appendix L). However, notwithstanding this, the AER acknowledges that Powercor and SP AusNet, with significant rural network coverage, are more exposed to bushfire risk, and will therefore incur more vegetation management and bushfire mitigation expenditure than CitiPower.

The AER considers that efficiency savings can be identified in this area based on the considerations identified above. The AER considers that the economies of scale factors for vegetation control, insulator washing and bushfire mitigation should be decreased from 75 per cent to 50 per cent recognising that Powercor and SP AusNet are subject to more bushfire risk relative to CitiPower. It follows that network growth for Powercor and SP AusNet should result in some increase in vegetation management maintenance. However, the AER maintains that CitiPower's economies of scale factor for these categories should remain at 75 per cent).

For the reasons above, the AER considers that an economies of scale factor of 75 per cent for CitiPower and 50 per cent for Powercor and SP AusNet is consistent with a total forecast opex that reasonably reflects the efficient costs of maintaining the quality, reliability and security of supply, and the reliability, safety and security of their distribution systems.[194]

CitiPower and Powercor - CHED services

The AER did not apply economies of scale adjustments for CitiPower and Powercor's for activities provided by CHED services in the draft decision. These services generally relate to the provision of corporate costs. For the final decision, the AER accepts all of CitiPower and Powercor's adjustments for these services as reasonable, with the exception of billing and revenue collection, for which CitiPower and Powercor proposed a 5 per cent economies of scale adjustment.

The AER acknowledges that billing and revenue collection, as an operation that involves customer interaction, is likely to increase with growth in customer numbers. However, the AER considers that significant economies of scale are achievable since the incremental increase in customers is not likely to result in an equivalent increase in the operating costs of already established billing and revenue collection systems. The AER considers that the operation of billing and revenue collection systems will

192 Energex, *Code of practice for powerline clearance and vegetation - version 1*, 6 October 2004 (referred to in Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 7).
193 Nuttall Consulting, *Advice to the AER on Opex Scale Escalation*, 29 July 2010, p. 7
194 NER, cl. 6.5.6(a)(3),(4).

achieve similar economies of scale to customer service, which CitiPower and Powercor proposed at 50 per cent. Therefore, the AER has adjusted billing and revenue collection from 5 per cent to 50 per cent on the basis that it is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand for standard control services.[195]

SP AusNet's operating expenditure adjustment

As mentioned above, SP AusNet considers the economies of scale factor applied to its operating expenditure should be revised (from 100 per cent) if the AER does not accept its IT capex spend.[196]

Taking into account the substitution possibilities between capital expenditure and operating expenditure (clause 6.5.6(e)(7) of the NER), the AER has accepted SP AusNet's view that the economies of scale factor should be revisited in light of SP AusNet's capex program. The AER in the final decision has allowed all of SP AusNet's IT capex (see chapter 8) so the AER considers that SP AusNet's operating expenditure should not be subject to any growth, as proposed by SP AusNet.[197] The AER considers that this is consistent with a total forecast opex that reasonably reflects the efficient costs of meeting or managing the expected demand for standard control services[198] because the AER agrees that with funding for its entire IT capex program, SP AusNet should be able to offset the costs of providing back office services for its growing customer base.[199]

Therefore, the AER has not applied any growth to SP AusNet's opex (that is, a 100 per cent economies of scale adjustment).

Summary of economies of scale adjustments

The AER's final adjustments to economies of scale factors are summarised in Table J.21.

195 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).
196 SP AusNet, *Revised regulatory proposal*, p. 196
197 ibid.
198 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).
199 SP AusNet, *Revised regulatory proposal*, p. 196

Table J.21 Summary of AER variations to economies of scale adjustments (per cent)

	Expenditure category	Revised proposal	Final Decision
CitiPower, Powercor, SP AusNet	Emergency maintenance	5	45
CitiPower, Powercor, SP AusNet	Overhead line maintenance (condition based maintenance)	5	45
CitiPower, Powercor	Pole defect management (condition based maintenance)	5	45
CitiPower, Powercor	Revenue – customer connections	5	50
CitiPower	Customer supply negotiations	50	50
CitiPower, Powercor	Salary expenditure	75	75
CitiPower, Powercor	Billing and revenue collection	5	50
Powercor, SP AusNet	Vegetation control, insulator washing and bushfire mitigation	5	50

Source: AER Analysis.

J.6.6.5 AER conclusion on economies of scale adjustments

For the reasons discussed above, the AER considers its adjustments to the Victorian DNSPs' economies of scale factors will form part of a total forecast opex that reasonably reflects the efficient costs of achieving the opex objectives.[200]

The AER revisions discussed above increase the economies of scale adjustments from an average of 34.1 per cent (DNSP revised proposals) to an average of 59.6 per cent (AER average). This compares to the draft decision average of 57.6 per cent. The AER's final decision for the economies of scale adjustment adopted for each Victorian DNSP is provided in 0.

Table J.22 AER conclusion on variations to economies of scale (per cent)

	DNSP revised proposal economies of scale			AER conclusion on economies of scale		
	Operating	**Maintenance**	**Total**	**Operating**	**Maintenance**	**Total**
CitiPower	69.7	13.6	**42.9**	72.8	25.1	**52.8**
Powercor	69.8	9.6	**32.3**	73.0	35.9	**50.2**
JEN	57.6	57.6	**57.6**	72.9	33.8	**63.7**
SP AusNet	100.0	5.0	**43.6**	100	40.3	**68.7**
United Energy	–	–	–	72.9	33.8	**62.1**

Source: AER analysis.

200 NER, cll. 6.5.6(c)(1), 6.5.6(a)(1),(3) and (4).

J.6.7 Capex/opex trade-off

In determining whether the AER is satisfied that the Victorian DNSPs’ proposals result in a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives, regard must be had to the opex factors, including the substitution possibilities between capex and opex under clause 6.5.6(e)(7) of the NER.

It is generally acknowledged that all other things being equal, replacing aging assets with new assets will reduce the required maintenance activity (refer to discussion in section J.6.6.4). This section reviews whether an adjustment needs to be made to the scale opex forecasts to reflect an acceleration of the DNSPs’ renewal capex programs.

J.6.7.1 AER draft decision

In the draft decision, the AER reduced the Victorian DNSPs' scale opex allowance to account for the impact of the substitution between capex and opex.[201]

The AER considered that increased RQM capex (as a proportion of a DNSP's asset base) would result in a slight reduction in the required operating and maintenance activity levels.

J.6.7.2 Victorian DNSP revised proposals

The Victorian DNSPs disagreed with the AER's variation and each of the DNSPs submitted that the adjustment be removed.[202]

In the draft decision, the AER acknowledged that:[203]

> In advising the AER in its 2011–16 South Australian distribution final determination, PB recommended the AER remove the additional top down adjustment on the basis that ETSA Utilities' revised proposal regarding the impact on opex from network age included consideration of the capex/opex trade-off...For this draft decision, on the basis of the information available, the AER considers the net impact to be a minor reduction in opex.

Following the draft decision, CitiPower and Powercor engaged SKM:[204]

> SKM has developed a rigorous, sophisticated capex/opex trade-off model that calculates the age of the network over a regulatory period at a detailed asset level. The model also calculates opex costs as a function of age calibrated against actual data.

In relation to the substitutability between capex and opex, CitiPower and Powercor noted:[205]

> SKM's analysis suggests that [CitiPower / Powercor]'s average network asset age, and the proportion of assets older than their regulatory life, is expected to increase in the next regulatory control period. This implies that

201 See appendix J of the draft decision

202 CitiPower, *Revised regulatory proposal*, pp. 228–230; Powercor, *Revised regulatory proposal*, pp. 218–220; JEN, *Revised regulatory proposal*, p. 120; SP AusNet, *Revised regulatory proposal*, pp. 198–199; United Energy, *Revised regulatory proposal*, p. 83.

203 Footnote 78 of appendix J of the draft decision

204 CitiPower, *Revised regulatory proposal*, p. 228; Powercor, *Revised regulatory proposal* p. 218.

205 CitiPower, *Revised regulatory proposal*, p. 228; Powercor, *Revised regulatory proposal* p. 218.

> when proper consideration is given to the characteristics of [CitiPower / Powercor]'s network, [CitiPower / Powercor]'s opex should be expected to increase (rather than decrease) in the next regulatory control period.

SKM considered that the draft decision capex/opex trade-off adjustment (which was initially adopted by PB in the South Australian distribution determination, but later removed[206]) was flawed for the following reasons:[207]

- it should not be applied as part of scale escalation
- it uses financial ratios (repex : replacement cost), which the AER specifically rejected in its selection of growth drivers
- it ignores the aging of the asset base as a whole
- not all opex is likely to be affected by age
- the repex : replacement cost ratio itself is flawed.

United Energy submitted that the AER failed to adequately consider the impact of aging assets.[208]

JEN submitted that:[209]

> It is unreasonable to assume JEN can realise the AER's anticipated benefits from [the capex/opex] trade-off if the AER does not also allow JEN its proposed step changes arising from its capex program and the capital program itself. To the extent the AER's final decision rejects these step changes. This trade-off deduction should be set to zero.

SP AusNet stated:[210]

> SP AusNet reiterates, that in accordance with the NER, it has proposed a Reliability and Quality maintain case for replacement Capex. This is designed to retain existing levels of risk, which leads to virtually no change in the weighted average remaining life of its asset base. This means that despite "older assets being the focus of a well targeted, prioritised and optimised asset replacement program", assets that aren't currently in that 'replacement bracket' will move into that bracket during the next regulatory control period, thus offsetting the reduction in operating costs caused by replacing those older assets.

206 The AER notes that in the South Australian distribution determination, PB recommended removing the capex/opex trade-off adjustment because SKM's age-opex modelling approach implicitly incorporated a capex/opex trade-off that reflected a more accurate approach than that taken by PB. The Victorian DNSPs have not proposed any age-opex adjustments.

207 SKM, *Review of AER draft decision–opex scale escalation for CitiPower and Powercor Australia*, 8 July, 2010, pp. 11–14.

208 United Energy, *Revised regulatory proposal*, p. 83.

209 JEN, *Revised regulatory proposal*, p. 120.

210 SP AusNet, *Revised regulatory proposal*, p. 199.

J.6.7.3 Submissions

The EUCV also raised the relationship between the level of replacement capital and forecast opex, noting that the impact of new replacement assets must be reflected by a reduction of opex.[211]

EnergyAustralia expressed strong concerns with the AER's assessment of capex/opex trade-off models.[212]

J.6.7.4 Issues and AER considerations

The AER acknowledges that a decision to maintain existing levels of risk regarding failures and service interruptions implies that the proportion of 'older assets' in the base year will remain relatively constant over the forthcoming regulatory control period. As a result, according to SP AusNet's submission above, the level of base year opex is sufficient to maintain existing levels of asset performance over the forthcoming regulatory control period. In terms of the substitutability of capex and opex, the result is no reduction in opex due to asset replacement over the forthcoming regulatory control period.

The AER maintains the view that replacing aging assets with new assets will reduce the required maintenance activity, as suggested by the EUCV. In the draft decision, the AER considered that, on the basis of the available information, the impact of an increasing RQM capex program will slightly reduce required opex.

However, in response to the draft decision, the Victorian DNSPs have presented new information in support of their view that maintaining asset and service performance may require an increase in RQM capex from historic levels (considering the aging asset base). The result is that the base year opex is likely to be a reasonable approximation of the required level of opex to maintain the existing asset base.

The AER also acknowledges that it is arguable that using financial ratios to determine a capex/opex trade-off is inconsistent with the view that financial measures are inappropriate as a driver for scale escalation opex.

Accordingly, the AER accepts the Victorian DNSPs' proposals to remove the capex/opex trade-off reduction to overall growth. The AER notes that the reduction in overall maintenance for new assets has been considered as part of the deliberations on the economies of scale adjustments. However, consideration of the increase in maintenance arising from aging assets has been included in the AER's decision to remove the capex/opex trade-off in this section. As a result, the removal of the capex/opex trade-off adjustment means the impact of aging assets is therefore not a justification for applying lower economies of scale factors for an increased maintenance allowance. This is discussed in section J.6.6.4.

J.6.7.5 AER conclusion on the capex/opex trade-off

For the reasons discussed above, the AER considers the removal of the capex/opex trade-off adjustment, as proposed by the Victorian DNSPs is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast

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[211] EUCV, *Submission to the AER*, August 2010, pp. 39–40.

[212] EnergyAustralia, *Submission to the AER*, 19 August 2010, p. 13.

and cost inputs required to meet or manage the expected demand for standard control services.[213] The AER also considers the removal of this adjustment reasonably reflects the efficient costs of achieving the opex objectives[214], on the basis that aging assets are not a justification for reduced economies of scale adjustments because of this change.

J.6.8 AER conclusion on net growth rates

After adjusting the DNSPs' revised proposals on growth rates, the AER’s conclusion on net growth rates is presented in Table J.23 and Table J.24.

Table J.23 AER variation to Victorian DNSPs' proposed net growth rates (per cent per annum)

	DNSP proposed net growth rates	AER variation	AER net growth rates[a]
CitiPower	1.3	–0.6	0.7
Powercor	1.5	–0.6	0.9
JEN	1.0	–0.5	0.5
SP AusNet	1.1	–0.5	0.6
United Energy	0.8	–0.5	0.3

Source: AER analysis
[a]Average annual growth rate applying the AER growth drivers from Table J.16, after adjustments for economies of scale from 0.

Table J.24 AER conclusion on net growth rates (per cent, per annum)

	Gross Growth Rate			Economies of scale			Net Growth Rate[a]		
	Opex	Maint	Total	Opex	Maint	Total	Opex	Maint	Total
CitiPower	1.7	1.2	**1.5**	72.8	25.1	**52.8**	0.5	0.9	**0.7**
Powercor	1.9	1.8	**1.8**	73.0	35.9	**50.2**	0.5	1.1	**0.9**
JEN	1.5	1.4	**1.5**	72.9	33.8	**63.7**	0.4	0.9	**0.5**
SP AusNet	1.7	2.1	**1.9**	100.0	40.3	**68.7**	0.0	1.3	**0.6**
United Energy	0.8	1.3	**0.9**	72.9	33.8	**62.1**	0.2	0.9	**0.3**

Source: AER analysis.
[a]Net growth rate = gross growth rate x (1 – economies of scale)

As mentioned in section J.6.4.5, United Energy's low net growth rate is due to low customer number growth compared to the other DNSPs, and a very high proportion of opex compared to maintenance expenditure. Although JEN and CitiPower have

213 NER, cll. 6.5.6(c)(3), 6.5.6(a)(1).
214 NER, cll. 6.5.6(c)(1), 6.5.6(a)(1), (3), (4).

similar growth rates, CitiPower has a higher net growth rate as CitiPower has an equal proportion of opex and maintenance expenditure. JEN, like United Energy, incurs significantly more opex than maintenance expenditure. SP AusNet's net growth is quite low compared to Powercor due to opex not being subject to any growth allowance.

For the reasons discussed in sections J.6.6.4 and J.6.7.4, the AER considers the AER's adjusted net growth rates will form part of a total forecast opex that reasonably reflect the opex criteria.

J.6.9 Top down analysis

In determining whether the AER is satisfied that the Victorian DNSPs' proposals reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives, regard must be had to the opex factors, including clause 6.5.6(e)(5) of the NER, which relates to the actual and expected operating expenditure of a DNSP during any preceding regulatory control period.

This section contains an industry wide comparison of the AER's net growth rate against the Victorian DNSPs' proposals and actual price deflated opex to ascertain the reasonableness of the allowance provided through its assessment.

The top down assessment is used as a cross check to inform the AER's final conclusions on the variations to the DNSPs' proposals and consequently the AER's final decision on the scale opex allowance, and is based on the requirement that the AER have regard to analysis undertaken by or for the AER and the actual and expected operating expenditure of the DNSPs in the preceding regulatory control period.[215].

In order to develop a like-for-like comparison of actual trend opex and the AER's scale opex allowance, actual opex is deflated to remove the impact of CPI and real input price changes.

As noted in the AER's draft decision, the ESCV, in its 2008 final decision on gas access arrangements represented the rate of change in opex according to the following formula:[216]

> Δ real opex = Δ opex price less Δ opex PFP plus Δ output quantity
> less Δ CPI

In this formula, the rate of change in opex is a function of real changes in input prices (net of CPI) and changes in output quantity net of changes in partial factor productivity (PFP).

In terms of examining the impact of growth in the size of the network, by removing the influence of CPI and input price movements, the resultant change in opex can be narrowed to growth in the size of the network (scale escalation) and PFP (identified gains – economies of scale and unidentified gains – technology improvements).

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215 NER, cll. 6.5.6(e)(3),(5).

216 ESCV, *Gas access arrangement review 2008–2012, final decision – public version*, 7 March 2008, p. 224.

The opex data presented in table j.25 below has been deflated to represent the residual changes due to growth and efficiency gains.

The opex data is sourced from the DNSPs' RINs and has been deflated using CPI and an ABS index of wage growth (as a proxy for input price changes).[217]

The trend in deflated opex has been established by taking the annual average rate of change between the first and second regulatory control periods[218] (2001–05 and 2006–09 respectively[219]). The average annual rate of change was computed over four periods (between the midpoints—2003 and 2007). The midpoints were calculated as the average opex for each regulatory control period.[220]

Where the rate of change in actual opex is greater than zero, the impact of growth has exceeded savings from realised efficiency gains. Where the rate of change in actual opex is less than zero the effect of efficiency gains has exceeded the impact of growth on opex.

The results in Table J.25 show that the impact of efficiency gains significantly outweighed the impact of growth over the preceding two regulatory control periods. Actual deflated opex fell between 2003 and 2007, being the midpoints of the prior and current periods (based on actual audited data), by 1.9 per cent per annum.[221] The results also reveal that the net reductions are greatest for operating costs as opposed to maintenance costs. This is consistent with the industry level growth rates applied by the AER (0.3 per cent per annum for operating costs and 1.1 per cent per annum for maintenance costs). Table J.25 also confirms that greater economies of scale are expected to be realised for operating costs.

The AER considers the difference in actual trend opex (–1.9 per cent per annum) and the AER's scale opex allowance (+0.7 per cent per annum) can be attributed to efficiency gains yet to be realised over the forthcoming regulatory control period, if the opex trend is expected to continue. Based on the actual trend opex, the future unidentified efficiency gains amount to 2.5 per cent per annum (0.6 per cent less −1.9 per cent).

Providing the Victorian DNSPs with the opportunity to realise future efficiency gains is of critical importance to customers as the base year revealed opex is continuously revised[222] and these efficiency savings are passed back to customers at each review.[223]

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217 ABS, *6345.0 Labour price index, Australia, total hourly rates of pay excluding bonuses: sector by industry, original (financial year index numbers for year ended June quarter)*, Private, electricity, gas, water and waste services. www.abs.gov.au.

218 Using actual audited opex.

219 In the final decision, the AER has included 2009 due to availability of data.

220 The average taken over the 2006 to 2009 period was also adjusted for step changes to ensure a like-for-like business as usual comparison with the 2001 to 2005 regulatory control period.

221 The AER notes that the inclusion of the 2009 actuals have reduced this figure from 2.4 per cent in the draft decision.

222 Consistent with the concept of dynamic efficiency gains.

223 See the efficiency benefit sharing scheme, chapter 14.

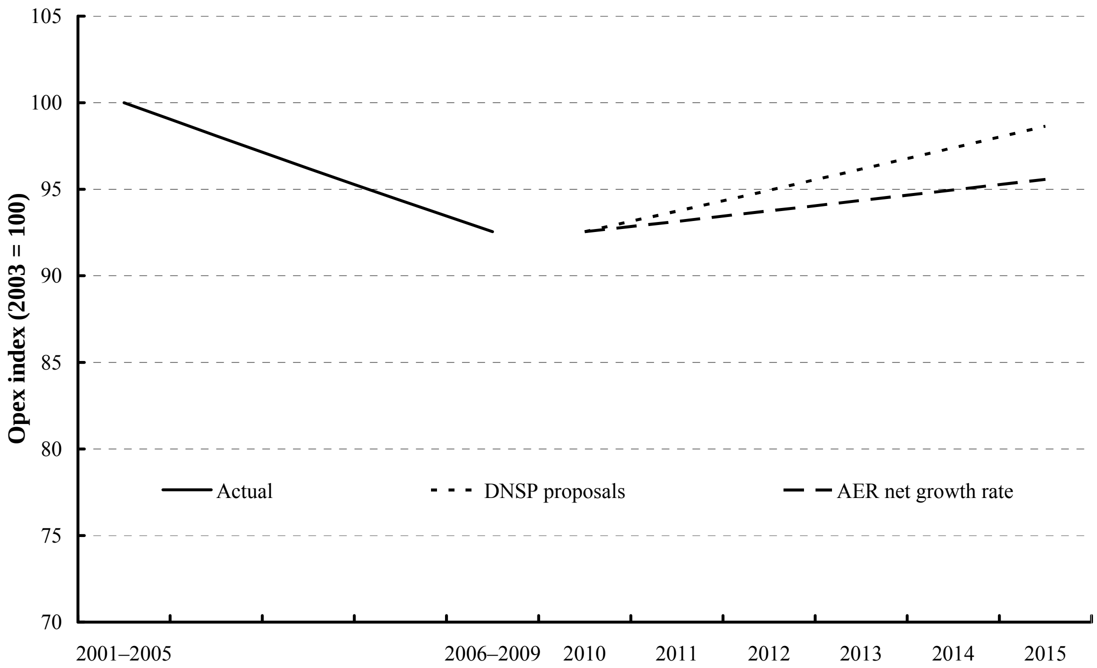
Table J.25 AER review of actual deflated opex (per cent, per annum)

	Operating costs change	Maintenance costs change	Total opex change
Industry trend (2003–2009) (including realised efficiency gains)	–3.9	1.0	–1.9
Industry trend DNSP revised proposals (2010–2015) (excluding unidentified efficiency gains)	0.5	2.1	1.3
Industry trend AER net growth rate (2010–2015) (excluding unidentified efficiency gains)	0.3	1.1	0.6

Source: AER analysis.

The results from Table J.25 are displayed in Figure J.1.

Figure J.1 AER top down opex trend analysis ($'m 2010)



Source: AER analysis.

Figure J.1 reveals that between the midpoints 2003 (index = 100) to 2007 actual deflated opex falls at a rate of 1.9 per cent per annum. Over the forthcoming regulatory control period, from the base year 2010, the scale opex allowance increases at a rate of 0.6 per cent per annum (AER net growth rate) compared to the DNSP proposals of 1.3 per cent per annum.

As noted above, if the trend in actual price deflated opex is expected to continue, the analysis suggests that the AER's scale opex allowance implicitly includes provision for future unidentified efficiency gains of 2.5 per cent per annum (0.6 less –1.9). The regulatory framework incentivises the Victorian DNSPs to pursue dynamic efficiency gains and ensures customers benefit from these efficiency gains at future reviews.

The AER considers its top down analysis shows the final scale opex allowance is consistent with a total forecast opex that reasonably reflects the efficient costs of achieving the opex objectives, and a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives[224] because the net growth rates applied should result in sufficient scope for the Victorian DNSPs to respond to network growth, whilst maintaining incentives for further efficiency improvements.

J.7 AER conclusion

This appendix has assessed the proposed allowance for scale escalation, which is one component of each Victorian DNSP's proposed total forecast operating expenditure. The AER considers that the growth rates in Table J.27 and the level of expenditure determined in Table J.28 of this appendix is consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast operating expenditure reasonably reflects the operating expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast operating expenditure.

That constituent decision, which should be read together with this appendix, is discussed in chapter 7.

Table J.26 Victorian DNSP revised proposals on scale escalation opex (per cent, per annum)

	Gross growth rate	Economies of scale adjustment	Net growth rate	Revised scale opex ($'m, 2010)
CitiPower	2.3	42.9	1.3	6.7
Powercor	2.3	32.3	1.5	28.7
JEN	2.4	57.6	1.0	8.4
SP AusNet	2.0	43.6	1.1	20.7
United Energy	–	–	0.8	–

Source: AER analysis of Victorian DNSPs' revised regulatory proposals, Victorian DNSPs' RINs, and Victorian DNSPs' cost escalation models.

[224] NER, cll. 6.5.6(c)(1),(3).

Table J.27 AER conclusion on scale escalation opex (per cent, per annum)

	Gross growth rate	Economies of scale adjustment	Net growth rate[a]	Final scale opex ($'m, 2010)
CitiPower	1.5	52.8	0.7	3.9
Powercor	1.8	50.2	0.9	17.7
JEN	1.5	63.7	0.6	3.8
SP AusNet	1.9	68.7	0.5	10.8
United Energy	0.9	62.1	0.3	4.8

Source: AER analysis
[a]Net growth rate = gross growth rate x (1 – economies of scale adjustment)

Table J.28 AER conclusion on scale escalation opex ($'m, 2010)

	2011	2012	2013	2014	2015	Total[a]
CitiPower	0.3	0.5	0.8	1.0	1.3	**3.9**
Powercor	1.2	2.3	3.5	4.7	5.9	**17.7**
JEN	0.3	0.5	0.8	1.0	1.3	**3.8**
SP AusNet	0.7	1.4	2.1	2.9	3.6	**10.8**
United Energy	0.3	0.6	1.0	1.3	1.6	**4.8**

Source: AER analysis
[a]Totals may not add due to rounding.

K Real cost escalators

In recent regulatory determinations for electricity network service providers, the AER has allowed capital expenditure (capex) and/or operating expenditure (opex) allowances to be escalated, in real terms, for expected input cost increases.[1] This involves the disaggregation of expenditure allowances into specific inputs (for example labour and materials) which are priced in terms of a base year. These base year costs are increased or decreased for each year of the regulatory control period relative to projected changes in the real price level. The nominal price level (that is the real price plus inflation) is taken into account when prices and revenues are adjusted at the aggregated level under the CPI–X control mechanism.

The methodology employed to determine the real cost escalators generally combines forecast movements in the price of input components with weightings for the relative contribution of each of the components to final equipment and project costs. This in turn generates real capex and opex forecasts for the regulatory control period. The weightings are typically specific to each regulated business, given differences in the composition of their respective expenditure forecasts.

This appendix sets out the AER's consideration of issues raised in response to the draft decision on labour and materials cost escalators for the Victorian distribution network service providers (DNSPs).

As noted at the beginning of both the capex and opex chapters, each Victorian DNSP proposed an allowance for real cost escalators as a component of their total proposed forecast capex and opex for the 2011–15 regulatory control period. The assessment of real cost escalators is relevant to determining whether the AER is satisfied that the total proposed forecast capex and opex, or its estimate of the required capex and opex, reasonably reflects the capex and opex criteria.

Specifically, this real cost escalators appendix assesses the proposed allowance and the level of efficient expenditure for labour and materials costs that a prudent operator, in the circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capex and opex objectives. This assessment in turn raises issues of general, non-labour and labour real cost escalation as they apply to the level of efficient expenditure for labour and materials costs that a prudent operator, in the actual circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capex and opex objectives.

As is discussed further in this appendix, the AER considers that the capex and opex factors, including the information included in and accompanying the Victorian DNSPs' proposals, submissions received in the course of consulting on the Victorian DNSPs' proposals, analysis undertaken for the AER by Access Economics and by the AER that was published before this distribution determination was made in its final

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1 For example, see AER, *Queensland distribution determination 2010–11 to 2014–15*, May 2010, pp. 397–413; and AER, *South Australian distribution determination 2010–11 to 2014–15*, May 2010, pp. 324–333.

form, the actual and expected opex of the Victorian DNSPs during preceding regulatory periods and the relative prices of operating and capital inputs are relevant to this assessment.

K.1 AER draft decision

The AER was not satisfied that the real escalation rates applied by the Victorian DNSPs to their proposed capex and opex forecasts reasonably reflected a realistic expectation of the cost inputs required to achieve the capex and opex objectives. In forming this view, the AER had regard to the capex and opex factors.[2]

The AER provided the Victorian DNSPs with the real cost escalators in tables K.1, K.2 and K.3 to escalate their capex and opex forecasts to account for projected real price movements in labour and materials costs.

Table K.1 AER draft decision on non-labour real cost escalators (per cent)

	2010	2011	2012	2013	2014	2015
Aluminium	39.8	7.2	1.4	–3.3	–5.4	–6.0
Copper	51.5	3.0	–3.3	–7.6	–9.9	–10.9
Steel	25.2	7.6	2.1	–1.1	–2.9	–3.5
Crude oil	40.2	7.8	–0.3	–1.6	–2.8	–3.1
Construction	1.2	0.5	1.9	2.8	1.7	–0.1

Source: AER, *Victorian distribution determination 2011–2015*, Draft decision, June 2010, Appendix K, pp. 120, 122, 124, and 145.

Table K.2 AER draft decision on internal labour real cost escalators (per cent)

	2010	2011	2012	2013	2014	2015
CitiPower	1.6	1.0	1.0	0.9	1.9	1.5
Powercor	1.9	1.0	1.0	0.9	1.9	1.5
JEN	1.6	1.0	1.0	0.9	1.9	1.5
SP AusNet	1.9	0.9	1.0	0.9	1.9	1.5
United Energy	1.1	1.1	1.0	0.9	1.9	1.5

Source: AER, *Draft decision*, Appendix K, p. 137.

2 Specifically, clauses 6.5.6(e)(1), 6.5.6(e)(2), 6.5.6(e)(3), 6.5.6(e)(5), 6.5.6(e)(6), 6.5.7(e)(1), 6.5.7(e)(2), 6.5.7(e)(3), 6.5.7(e)(5) and 6.5.7(e)(6) of the NER.

Table K.3 AER draft decision on outsourced services labour real cost escalators (per cent)

	2010	2011	2012	2013	2014	2015
CitiPower	0.7	0.9	1.5	1.9	1.9	0.7
Powercor	0.7	0.9	1.5	1.9	1.9	0.7
JEN	0.7	0.9	1.5	1.9	1.9	0.7
SP AusNet	0.7	0.9	1.5	1.9	1.9	0.7
United Energy	0.7	0.9	1.5	1.9	1.9	0.7

Source: AER, *Draft decision*, Appendix K, p. 138.

K.2 Revised proposals

The Victorian DNSPs escalated their capex and opex forecasts for labour and materials real price movements as forecast by BIS Shrapnel, KPMG Econtech and Sinclair Knight Merz (SKM).

In regards to non-labour costs, SKM revised its methodology for forecasting materials real cost escalators to address most of the concerns raised by the AER in the draft decision.

In regards to labour costs, however, the Victorian DNSPs disagreed with the AER's approach to forecasting labour cost escalators. Specifically, the Victorian DNSPs disagreed with the AER's draft decision regarding:

- the use of a labour price index (LPI), as opposed to average weekly ordinary time earnings (AWOTE), as the most appropriate wage measure[3]
- the preference for using the most up-to-date forecasts[4]
- the use of a weighted average to determine the internal labour cost escalators[5]
- the use of general labour costs (as a proxy for movements in the property and business services sector) in determining the outsourced services labour cost escalators[6]

3 CitiPower, *Revised regulatory proposal*, pp. 235–238; Powercor, *Revised regulatory proposal*, pp. 225–228; JEN, *Revised regulatory proposal*, pp. 177–179; SP AusNet, *Revised regulatory proposal*, pp. 177–180; United Energy, *Revised regulatory proposal*, p. 84.

4 The Victorian DNSPs (with the exception of United Energy) perceived this as a primary driver for the AER rejecting their proposals. CitiPower, *Revised regulatory proposal*, p. 238; Powercor, *Revised regulatory proposal*, p. 228; JEN, *Revised regulatory proposal*, pp. 187–188; SP AusNet, *Revised regulatory proposal*, p. 181.

5 CitiPower, *Revised regulatory proposal*, pp. 242–243; Powercor, *Revised regulatory proposal*, pp. 232–233; JEN, *Revised regulatory proposal*, pp. 180–182; SP AusNet, *Revised regulatory proposal*, pp. 186–188.

6 CitiPower, *Revised regulatory proposal*, pp. 243–244; Powercor, *Revised regulatory proposal*, p. 234; JEN, *Revised regulatory proposal*, pp. 182–183; SP AusNet, *Revised regulatory proposal*, pp. 182–183.

- the reliance on Access Economics' forecasts.[7]

The specific issues raised in the Victorian DNSPs revised regulatory proposals are discussed in further detail throughout the remainder of this appendix.

K.3 Submissions

The AER received submissions regarding the escalation of labour and materials costs for forecast real price movements from EnergyAustralia and the Energy Users Coalition of Victoria (EUCV).

K.4 Consultant review

In response to the Victorian DNSPs' revised regulatory proposals, the AER engaged Access Economics to update its March 2010 labour cost forecasts for the Australian Capital Territory, New South Wales, Queensland, South Australia, Victoria, and Australia. Access Economics updated its March 2010 cost forecasts for general labour, as well as labour costs for the electricity, gas, water and waste services (EGW) and construction sectors. Access Economics also provided forecast labour cost movements for the administrative and support services sector for the Australian Capital Territory, New South Wales, Queensland, South Australia, Victoria, and Australia.[8]

K.5 Issues and AER considerations

K.5.1 Real cost escalation

K.5.1.1 AER draft decision

Consistent with past electricity distribution determinations for the Australian Capital Territory, New South Wales, Queensland and South Australia, the AER applied real cost escalation for forecast input cost increases to the Victorian DNSPs' capex and opex forecasts.[9]

K.5.1.2 Victorian DNSP revised regulatory proposals

Consistent with their initial regulatory proposals and the AER's draft decision, CitiPower, Powercor, Jemena Electricity Networks (JEN) and SP AusNet applied real cost escalators to their capex and opex forecasts in their revised regulatory proposals.[10] United Energy, however, only applied real cost escalators to the labour component of its in-house opex, reflecting its different forecasting approach.[11]

7 CitiPower, *Revised regulatory proposal*, pp. 239–240; Powercor, *Revised regulatory proposal*, pp. 229–230; JEN, *Revised regulatory proposal*, pp. 183–186; SP AusNet, *Revised regulatory proposal*, pp. 185–187; United Energy, *Revised regulatory proposal*, p. 84.

8 Access Economics, *Forecast growth in labour costs: update of March 2010 report*, 20 September 2010.

9 AER, *Draft decision*, Appendix K, pp. 114–153.

10 CitiPower, *Revised regulatory proposal*, pp. 245–246; Powercor, *Revised regulatory proposal*, p. 236; JEN, *Revised regulatory proposal*, p. 193; SP AusNet, *Revised regulatory proposal*, p. 175.

11 United Energy, *Revised regulatory proposal*, pp. 83–85.

K.5.1.3 Submissions

EnergyAustralia stated that the AER's decisions should be subject to the same transparent process as applied to submissions and should make its cost escalation model available, with any confidential information removed as necessary.[12]

The EUCV acknowledged that the AER's application of real cost escalators attempts to recognise the costs the DNSPs will incur over time. The EUCV, however, considered that the real cost escalators have proven to be uniformly wrong and have introduced a conservatism into allowances that consumers have had to pay for.[13]

The EUCV proposed two different approaches to the escalation of real cost increases:

1. escalating by CPI only
2. using an 'energy industry inflation adjustor' in the control mechanism rather than CPI.[14]

K.5.1.4 Issues and AER considerations

The AER notes EnergyAustralia's comments on the transparency of the AER's real cost escalation model. The model will be made available to stakeholders on request, with confidential information removed.

The AER also notes the EUCV's proposal that cost increases should be escalated by CPI only. However, under the capex and opex criteria in the National Electricity Rules (NER), the AER must be satisfied that the capex and opex provided to the DNSPs reasonably reflects a realistic expectation of the cost inputs required. Having regard to the information included in the Victorian DNSPs' revised regulatory proposals, and analysis undertaken by Access Economics for the AER, the AER considers that there is strong evidence that labour and materials costs during the forthcoming regulatory control period will increase at a rate different to CPI. The AER must take this into account when assessing the Victorian DNSPs' capex and opex proposals.

The AER notes that clause 6.2.6 of the NER requires that, for standard control services, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form. Further, the NER defines CPI as the consumer price index as published by the Australian Bureau of Statistics. If that index ceases to be published or is substantially changed, the AER may determine a suitable benchmark for recording general movements in prices. Since the ABS has not ceased publishing the CPI, or substantially changed it, the AER considers that it is bound by the NER to use CPI in the control mechanism rather than an 'energy industry inflation adjustor' as proposed by the EUCV.

K.5.1.5 AER conclusion

The AER is satisfied that the escalation of forecast capex and opex for forecast real cost movements, as proposed by the Victorian DNSPs, is consistent with total capex and opex allowances that reasonably reflects a realistic expectation of the cost inputs

12 EnergyAustralia, Submission, 19 August 2010, p. 7.
13 EUCV, Submission, August 2010, p. 24.
14 EUCV, Submission, 19 August 2010, pp. 24–25.

required to achieve the capex and opex objectives.[15] In coming to this view, the AER has had regard to the capex and opex factors.[16]

K.5.2 Non-labour costs

K.5.2.1 AER draft decision

The AER considered that the method proposed by SKM to forecast the escalation of aluminium, copper, steel and crude oil was broadly consistent with the method used by the AER in recent determinations for other DNSPs in South Australia, Queensland, New South Wales and the Australian Capital Territory. However, the AER was not satisfied that SKM's approach to forecasting exchange rates to restate the US dollar based market prices of these materials reasonably reflected a realistic expectation of cost inputs.[17]

Further, the AER considered that SKM's application of engineering construction cost forecasts, cost escalation of wood poles and the adjustment of imported equipment costs by movements in the trade weighted index (TWI) reasonably reflected a realistic expectation of cost inputs.[18]

The AER also considered that the real cost escalators applied by the Victorian DNSPs should not include any explicit consideration of a carbon pollution reduction scheme (CPRS).[19]

Lastly, the AER considered that forecast materials cost escalators should be updated using the most recent data available.[20]

K.5.2.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs engaged SKM to update the real cost escalation rates for materials.[21] In its updated report, SKM considered the AER's assessment of materials cost escalators and revised its methodology to:

- incorporate the exchange rate forecast used by AER in the draft decision
- remove the CPRS/carbon component
- remove the real cost escalation of wood poles
- remove the adjustment for the TWI.[22]

15 Clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER.
16 Specifically, clauses 6.5.6(e)(1), 6.5.6(e)(2), 6.5.6(e)(3), 6.5.7(e)(1), 6.5.7(e)(2) and 6.5.7(e)(3) of the NER.
17 AER, *Draft decision*, Appendix K, pp. 119–123.
18 AER, *Draft decision*, Appendix K, pp. 142–143.
19 AER, *Draft decision*, Appendix K, p. 140.
20 AER, *Draft decision*, Appendix K, p. 140.
21 SKM, *Victorian Distribution Network Service Providers cost escalator updates*, Final report, 8 July 2010 (CitiPower, *Revised regulatory proposal*, Attachment 155, 21 July 2010; Powercor, *Revised regulatory proposal*, Attachment 155, 21 July 2010; JEN, *Revised regulatory proposal*, Appendix 8.3, 20 July 2010. SP AusNet and United Energy did not attach this report to their revised regulatory proposals.)

SKM did not, however, amend its methodology for converting financial year construction cost forecasts to a calendar year basis.[23]

SKM's forecast real cost escalation rates are outlined in table K.4.

Table K.4 SKM's revised non-labour real cost escalators (per cent)

	2009	2010	2011	2012	2013	2014	2015
Aluminium	–32.1	26.3	19.6	–0.3	–1.5	–3.5	–3.3
Copper	–22.2	35.2	14.9	–4.9	–6.0	–8.1	–8.2
Steel	–41.9	21.4	12.6	–4.7	–0.4	–1.6	–1.4
Oil	–33.3	15.4	16.5	–0.7	0.1	–1.6	–1.2
Construction costs	1.0	–0.1	–0.2	1.3	1.9	0.7	–0.8

Source: SKM, *Victorian Distribution Network Service Providers cost escalator updates*, Final report, 8 July 2010, p. 15.

In their revised proposals, CitiPower, Powercor and JEN applied the escalators provided by SKM in its updated report.[24] CitiPower and Powercor noted that they will update their materials cost forecasts closer to the date of the AER's final decision to address any concerns the AER may have regarding the currency of the forecasts.[25]

SP AusNet stated that it has not explicitly included the impact of materials cost escalators in the development of its capex forecasts, but stated that it will engage SKM to update its forecasts to include materials cost escalators in the AER's final decision.[26] Although SP AusNet did not include SKM's report as an attachment to its revised regulatory proposal, the AER notes that SP AusNet provided SKM's materials escalator rates, and the resultant impact on SP AusNet's capex program.[27] SP AusNet subsequently submitted updated materials cost escalators on 17 September 2010.

SP AusNet's escalators are outlined in table K.5.

22 SKM, *Victorian Distribution Network Service Providers cost escalator updates*, Final report, 8 July 2010, p. 14.
23 SKM, *Victorian Distribution Network Service Providers cost escalator updates*, Final report, 8 July 2010, pp. 10–12.
24 CitiPower, *Revised regulatory proposal*, pp. 244–246; Powercor, *Revised regulatory proposal*, pp. 235–236; JEN, *Revised regulatory proposal*, pp. 191–193.
25 CitiPower, *Revised regulatory proposal*, p. 245; Powercor, *Revised regulatory proposal*, p. 235.
26 SP AusNet, *Revised regulatory proposal*, p. 162.
27 SP AusNet, *Revised regulatory proposal*, p. 163.

Table K.5 SP AusNet's revised non-labour real cost escalators (per cent)

	2009	2010	2011	2012	2013	2014	2015
Aluminium	–32.1	9.0	17.7	0.6	1.1	–0.7	–0.6
Copper	–22.2	18.3	14.3	–4.6	–4.2	–5.8	–5.7
Steel	–41.9	17.4	20.8	–2.0	–2.1	–2.0	–1.8
Oil	–33.3	10.7	21.9	0.9	0.1	–2.1	–1.7
Construction costs	–4.8	–4.6	–0.8	–1.6	–1.4	0.3	1.9

Source: SP AusNet, *Letter to AER re updated materials cost escalators*, 17 September 2010, p. 3.

Consistent with its initial regulatory proposal, United Energy did not apply any non-labour input cost escalators to its revised regulatory proposal.

K.5.2.3 Submissions

EnergyAustralia stated that since the AER's final determination for EnergyAustralia, it has entered into a supply contract for financial year 2009 that increased its wood pole costs by 6 per cent. The key drivers for this cost increase were royalty, labour and chemical cost increases. EnergyAustralia stated that if the Victorian DNSPs purchase wood poles at the same cost, then escalating the Victorian DNSPs wood pole costs by CPI only will not adequately cover wood pole price increases.[28]

The EUCV expressed concern over the accuracy of the exchange rate forecasts adopted by the AER. It stated that the forecasts have shown extreme volatility and were likely to be incorrect later in a regulatory period, providing either a large benefit or detriment to the DNSPs over a five year regulatory control period. The EUCV also considered that the forecasts used by the AER were biased to conservatism. [29]

K.5.2.4 Issues and AER considerations

The AER notes that in preparing the non-labour cost escalators for the Victorian DNSPs, SKM:

- incorporated the exchange rate forecast used by AER in the draft decision
- removed the CPRS/carbon component
- removed the real cost escalation of wood poles
- removed the adjustment for the TWI.[30]

SKM did not, however, amend its methodology for converting financial year construction cost forecasts to a calendar year basis.[31]

[28] EnergyAustralia, Submission, 19 August 201, pp. 7–8.
[29] EUCV, Submission, 19 August 2010, pp. 25–26.
[30] SKM, *Victorian Distribution Network Service Providers cost escalator updates*, Final report, 8 July 2010, p. 14.

The AER has updated its forecasts of non-labour real cost price movements, which are outlined in table K.6.

Table K.6 AER updated non-labour real cost escalators (per cent)

	2009	2010	2011	2012	2013	2014	2015
Aluminium	–32.1	10.5	20.1	6.3	1.0	0.2	–0.4
Copper	–22.3	23.8	20.7	1.1	–5.0	–6.0	–6.6
Steel	–40.0	9.9	20.3	3.9	–1.0	0.2	–0.4
Oil	–34.9	9.3	21.4	6.8	–0.4	–1.8	–2.0

Source: AER analysis.

The AER notes some deviation between the real cost escalators forecast by SKM and those forecast by the AER. Without having access to SKM's model the AER has been unable to determine the exact causes of this discrepancy. The AER notes, however, that the AER's forecasts are based on one month more market data and considers this to be the most likely cause of the discrepancy.

Despite the fact that the non-labour real cost escalators forecast by the AER are based on more current data, the AER notes that there have only been modest movements in the relevant materials markets in the intervening time. The price of aluminium, copper and steel have all appreciated in American dollar terms in the time since SP AusNet submitted SKM's revised real cost escalators. However, in the same time the Australian dollar has appreciated against the US dollar and all of these materials, as well as oil, have become cheaper in Australian dollar terms.

Despite this, the non-labour real cost escalators forecast by the AER generally project slightly stronger growth than do SKM's. This largely reflects the fact that the AER model incorporates slightly stronger futures prices for materials in US dollar terms but assumes the same exchange rate forecasts as does the SKM model because revised economic forecasts of the exchange rate have not been released. Since the Australian dollar has appreciated in the intervening time the AER considers that its projected real non-labour cost estimates may slightly over estimate the future growth in materials prices.

Further, the AER notes that the non-labour real cost escalators forecast by SKM rely on the same long term economic forecasts for aluminium, copper and steel as the AER forecasts. Having had regard to these considerations, the AER is satisfied that the proposed aluminium, copper, steel and oil real cost escalators projected by SKM and submitted by SP AusNet on 17 September 2010 reasonably reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives.

The AER notes SKM's concerns with the AER's approach to converting financial year construction cost forecasts to a calendar year basis. The AER considers that its approach is consistent with advice from KPMG Econtech, which model the

[31] SKM, *Victorian Distribution Network Service Providers cost escalator updates*, Final report, 8 July 2010, pp. 10–12.

construction cost forecasts for the Construction Forecasting Council (CFC).[32] Regardless, the AER notes that it has not used the CFC construction forecasts to escalate the cost of construction labour. Instead, for the reasons discussed in section K.5.3.10, the AER considers that the construction labour cost forecasts modelled by Access Economics, which also convert financial year construction cost forecasts to a calendar year basis, reasonably reflect a realistic expectation of the cost inputs required. In forming this view, the AER has had particular regard to the information included in the Victorian DNSPs' revised regulatory proposals.[33]

The AER notes EnergyAustralia's concerns regarding the escalation of wood pole costs. However, the AER also notes that Victorian DNSPs have escalated wood pole costs by CPI only in their revised regulatory proposals, consistent with the AER's draft decision.

The AER notes the EUCV's concerns over the accuracy of the exchange rate forecasts adopted by the AER. The AER recognises the EUCV's concerns but notes that the exchange rate itself can be extremely volatile and change significantly over a short period of time. The AER considers, however, that KPMG Econtech's exchange rate forecasts, as published in its ANSIO report, are robust given that they are derived from a credible source of information that is based on the views of respected professional economic forecasters. Consistent with the draft decision, and the Victorian DNSPs' revised regulatory proposals, the AER has adopted the latest exchange rate forecasts available from KPMG Econtech in this final decision. It notes, however, that exchange rates have risen since KPMG Econtech released these forecasts.

Table K.7 AER conclusion on exchange rates (US cents / $AUD)

2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
96.3[h]	81.1[h]	85.2[h]	73.8[f]	71.9[f]	71.6[f]	72.1[f]	73.0[f]

Note: Exchange rate forecasts are for the beginning of the period.
(h) historic exchange rate
(f) forecast exchange rate
Source: RBA, www.rba.gov.au/statistics/hist-exchange-rates/index.html, viewed 13 October 2010; KPMG Econtech, *Australian national, state and industry outlook*, August 2010, p. 102.

K.5.2.5 AER conclusion

The AER is not satisfied that the proposed aluminium, copper, steel and oil real cost escalators are consistent with capex and opex allowances that reasonably reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives.[34] In coming to this view, the AER has had regard to the information included in the Victorian DNSPs' revised regulatory proposals, and analysis undertaken by the AER for its draft decision.[35]

32 KPMG Econtech, *Updated Labour Cost Growth Forecasts*, 25 March 2009, pp. 23–24.
33 Consistent with clause 6.5.6(e) (1) and 6.5.7(e) (1) of the NER.
34 Clauses 6.5.6(c) (3) and 6.5.7(c) (3) of the NER.
35 Clauses 6.5.6(e) (1), 6.5.6(e) (3), 6.5.7(e) (1) and 6.5.7(e) (3) of the NER.

The AER has substituted the escalators proposed by the Victorian DNSPs with the escalators in table K.5, as revised by SKM and submitted by SP AusNet on 17 September 2010, and considers these adjustments are the minimum necessary for the AER to be satisfied that these escalators reasonably reflect the capex and opex criteria.[36] In coming to this view, the AER has had regard to the information included in the Victorian DNSPs' revised regulatory proposals, and analysis undertaken by the AER for its draft decision.

K.5.3 Labour

K.5.3.1 AER draft decision

The AER did not accept the methodologies used to develop the real labour cost escalators within the Victorian DNSPs’ regulatory proposals. In particular, the AER was not satisfied that the proposed labour escalation rates reasonably reflected the costs likely to be incurred by a prudent service provider operating in the circumstances of the Victorian DNSPs because the:

- labour cost forecasts were based on an average weekly earnings (AWE) measure
- labour costs forecasts did not appear to accurately consider the actual composition of its internal and contract service labour resources by labour type
- forecasts developed by BIS Shrapnel in August 2009 were no longer based on the latest available information and expectations

K.5.3.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs disagreed with the AER’s draft decision with respect to labour cost escalators.[37] Instead, the Victorian DNSPs proposed the revised escalation rates shown in tables K.8 and K.9.

Table K.8 Victorian DNSPs proposed real internal labour escalation rates (per cent)

	2010	2011	2012	2013	2014	2015
CitiPower	3.2	2.5	2.5	2.6	2.6	2.5
Powercor	3.2	2.5	2.5	2.6	2.6	2.5
JEN	3.8	2.4	2.6	2.7	2.6	2.4
SP AusNet	3.4	2.9	2.6	2.7	2.6	2.4
United Energy	2.2	2.2	2.2	2.2	2.2	2.2

Source: CitiPower, *Revised regulatory proposal*, p. 233; Powercor, *Revised regulatory proposal*, p. 223; JEN, *Revised regulatory proposal*, p. 175; SP AusNet, *Revised regulatory proposal*, p. 177; United Energy, *Revised regulatory proposal*, p. 84.

36 Clauses 6.5.6(c) (3) and 6.5.7(c) (3) of the NER.
37 The labour escalators determined in the AER’s draft decision are provided in tables K.2 and K.3.

Table K.9 Victorian DNSPs proposed real outsourced escalation rates (per cent)

	2010	2011	2012	2013	2014	2015
CitiPower	3.6	1.9	2.3	2.8	2.7	2.4
Powercor	3.6	1.9	2.3	2.8	2.7	2.4
JEN	3.0	1.9	2.6	3.0	2.5	2.3
SP AusNet	3.1	2.4	2.6	3.0	2.5	2.3
United Energy	–	–	–	–	–	–

Source: CitiPower, *Revised regulatory proposal*, p. 233; Powercor, *Revised regulatory proposal*, p. 223; JEN, *Revised regulatory proposal*, p. 175; SP AusNet, *Revised regulatory proposal*, p. 177.

For their revised regulatory proposals, CitiPower and Powercor applied escalators based on forecasts modelled by KPMG Econtech. SP AusNet's and United Energy's revised proposals both reflected forecasts modelled by BIS Shrapnel. JEN's revised labour cost escalators represented an average of the labour costs forecast by KPMG Econtech and BIS Shrapnel. These escalators all reflected forecasts based on average weekly ordinary time earnings (AWOTE).

The Victorian DNSPs disagreed with the AER's draft decision in regard to:

- the use of a labour price index (LPI), as opposed to average weekly ordinary time earnings (AWOTE), as the most appropriate wage measure[38]
- the preference for utilising the most up-to-date forecasts[39]
- the use of a weighted average to determine the internal labour cost escalators[40]
- the use of general labour costs (as a proxy for movements in the property and business services sector) in determining the outsourced services labour cost escalators[41]
- the reliance on Access Economics' forecasts.[42]

38 CitiPower, *Revised regulatory proposal*, pp. 235–238; Powercor, *Revised regulatory proposal*, pp. 225–228; JEN, *Revised regulatory proposal*, pp. 177–179; SP AusNet, *Revised regulatory proposal*, pp. 177–180; United Energy, *Revised regulatory proposal*, p. 84.

39 The Victorian DNSPs (with the exception of United Energy) perceived this as a primary driver for the AER rejecting their proposals. CitiPower, *Revised regulatory proposal*, p. 238; Powercor, *Revised regulatory proposal*, p. 228; JEN, *Revised regulatory proposal*, pp. 187–188; SP AusNet, *Revised regulatory proposal*, p. 181.

40 CitiPower, *Revised regulatory proposal*, pp. 242–243; Powercor, *Revised regulatory proposal*, pp. 232–233; JEN, *Revised regulatory proposal*, pp. 180–182; SP AusNet, *Revised regulatory proposal*, pp. 186–188.

41 CitiPower, *Revised regulatory proposal*, pp. 243–244; Powercor, *Revised regulatory proposal*, p. 234; JEN, *Revised regulatory proposal*, pp. 182–183; SP AusNet, *Revised regulatory proposal*, pp. 182–183.

CitiPower and Powercor

In addition to the issues raised above, and contrary to the AER's draft decision, CitiPower's and Powercor's revised regulatory proposals considered that the forecasts used to escalate labour costs should not take productivity improvements into account.[43] CitiPower and Powercor reasoned that doing so would distort the incentives for efficiency that are otherwise created by the AER's efficiency benefit sharing scheme (EBSS).

Similarly, CitiPower and Powercor considered that the AER's EBSS continued to provide an incentive for DNSPs to strongly negotiate EBA rates.[44] Accordingly, CitiPower and Powercor considered that it is reasonable to adopt actual EBA wage increases in the current regulatory control period.

JEN

In addition to the issues raised above, JEN's revised regulatory proposal considered that the CFC forecasts utilised by the AER in determining the outsourced services labour cost escalators were incorrectly applied. As a result, JEN considered that the outsourced services labour cost escalators were underestimated.[45]

K.5.3.3 Consultant review

The AER engaged Access Economics to update its growth forecasts for general labour for the Australian Capital Territory, New South Wales, Queensland, South Australia, Victoria, and nationally. The AER also requested Access Economics to update its growth forecasts for the electricity, gas, water and waste services, construction, and administrative and support services sectors.

Generally, Access Economics noted that developments in recent months have affected the wage outlook provided in its previous update for the AER.[46] Specific to Victoria, Access Economics considered the short term outlook for the economy to be less optimistic than at the time of its March 2010 update. Moreover, Access Economics noted that recent gains evident in job growth were now easing back.[47]

Access Economics also noted that, with respect to the EGW sector, emerging economies have been stronger than projected at the time of the March 2010 update. Correspondingly, there have been some positive demand impacts for the utilities sector. Access Economics, however, also acknowledged some negative impacts, such

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42 CitiPower, *Revised regulatory proposal*, pp. 239–240; Powercor, *Revised regulatory proposal*, pp. 229–230; JEN, *Revised regulatory proposal*, pp. 183–186; SP AusNet, *Revised regulatory proposal*, pp. 185–187; United Energy, *Revised regulatory proposal*, p. 84.

43 CitiPower, *Revised regulatory proposal*, p. 238; Powercor, *Revised regulatory proposal*, p. 228.

44 CitiPower, *Revised regulatory proposal*, pp. 241–242; Powercor, *Revised regulatory proposal*, p. 232.

45 JEN, *Revised regulatory proposal*, pp. 182–183.

46 Access Economics, *Forecast growth in labour costs: update of March 2010 report*, 20 September 2010, p. iv.

47 Access Economics, *Forecast growth in labour costs: update of March 2010 report*, 20 September 2010, p. 17.

as the relative weaknesses in the manufacturing sector and the continuing uncertainty over carbon pricing.[48]

The updated LPI projections, as provided by Access Economics, are set out in table K.10 below.

Table K.10 Access Economics proposed Victorian real labour cost escalators (per cent)

	2010	2011	2012	2013	2014	2015
General	–0.4	0.8	2.0	2.5	3.2	2.1
EGW	0.5	1.3	2.0	2.4	3.3	2.2
Construction	0.7	1.5	2.2	2.5	3.3	2.2
Administration services	–1.3	0.2	1.4	2.3	3.0	1.9

Source: Access Economics, *Forecast growth in labour costs: update of March 2010 report*, 20 September 2010, p. 54.

K.5.3.4 Wage measures

As noted, the labour cost escalators incorporated in the Victorian DNSPs' initial regulatory proposals were based on BIS Shrapnel's AWOTE forecasts. Conversely, the AER's draft decision considered that the LPI more reasonably reflected the labour costs that a Victorian DNSP is likely to incur.[49]

The AER's draft decision also acknowledged that while there are drawbacks to both LPI and AWOTE measures, Access Economics and the ABS stated a preference for the LPI when measuring changes in wage rates.[50]

The Victorian DNSPs, however, disagreed with the AER's draft decision. Instead, consistent with their initial regulatory proposals, the Victorian DNSPs' revised regulatory proposals considered that labour cost escalators should reflect forecast movements in AWOTE. To support their proposals, the Victorian DNSPs submitted reports by both BIS Shrapnel and KPMG Econtech.[51]

The BIS Shrapnel report was an update to the report provided with the Victorian DNSPs' initial regulatory proposals. It compared the AWOTE and LPI wage measures and noted that:

> The LPI also does not reliably measure the changes in total labour costs which the Victorian DNSPs incur, because the LPI does not reflect changes in the skill levels of employees within an enterprise or industry … [T]he change in the cost of labour over, say a year, includes increases in the base pay rates (which the LPI measures) and the higher average base pay level.

48 Access Economics, *Forecast growth in labour costs: update of March 2010 report*, 20 September 2010, p. 29.

49 AER, *Draft decision*, Appendix K, p. 132.

50 AER, *Draft decision*, Appendix K, p. 132.

51 The KPMG Econtech reports were commissioned by CitiPower, Powercor and JEN, while the BIS Shrapnel reports were commissioned by JEN, SP AusNet and United Energy.

> The AWOTE captures both these elements, while the LPI only captures the first element …
>
> For this reason, BIS Shrapnel prefers using AWOTE as the measure that best reflects the increase in wages cost changes …[52]

Similarly, the KPMG Econtech report concluded that labour cost escalators should be based on AWOTE:

> Overall, we [KPMG Econtech] would suggest that AWOTE is more suitable for the current analysis, which aims to forecast realistic labour cost changes for the DNSPs over the coming five years. In the current economic climate, compositional impacts, as well as competition between industries, are playing an influential role in the overall labour costs faced by employers … Such changes are not captured by the LPI, but are captured by AWOTE. [53]

CitiPower, Powercor and United Energy also considered that the AER's decision was inconsistent with previous AER determinations.[54]

Additionally, SP AusNet noted that the composition of the workforce employed now may not represent the least cost technically efficient suite of workers required to provide those services in the future. SP AusNet concluded, therefore, that the utilisation of the LPI is inconsistent with the statutory requirements on the AER under the NER and National Electricity Law (NEL).[55]

AER considerations

The AER considers that, consistent with the NEL, the rationale for real labour cost escalation is to provide DNSPs with a reasonable opportunity to recover at least the efficient costs of providing direct control network services.[56] The AER has also had regard to the NER. Specifically, the AER considers that real labour cost escalators should facilitate capex and opex forecasts that reasonably reflect both the efficient costs of achieving the capex and opex objectives, and a realistic expectation of the costs inputs required to achieve the capex and opex objectives.[57]

To the extent that the incentives within the regulatory framework assume current labour costs are efficient, the AER considers that satisfying both the NEL and NER requires compensating a DNSP purely for expected changes in the price of labour. That is, changes in the costs to a DNSP of employing labour, unaffected by compositional changes in the quality or quantity of work performed.[58]

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52 BIS Shrapnel, *Wages outlook for the electricity distribution sector in Victoria*, July 2010, p. 21.

53 KPMG Econtech, *Assessment of the AER's draft decision on labour cost escalation: Victoria*, 13 July 2010, p. 19.

54 CitiPower, *Revised regulatory proposal*, p. 236; Powercor, *Revised regulatory proposal*, pp. 226; United Energy, *Revised regulatory proposal*, p. 84.

55 SP AusNet, *Revised regulatory proposal*, p. 180.

56 Clause 7A(2) of the NEL.

57 Clauses 6.5.6(c)(1), 6.5.6(c)(3), 6.5.7(c)(1) and 6.5.7(c)(3) of the NER.

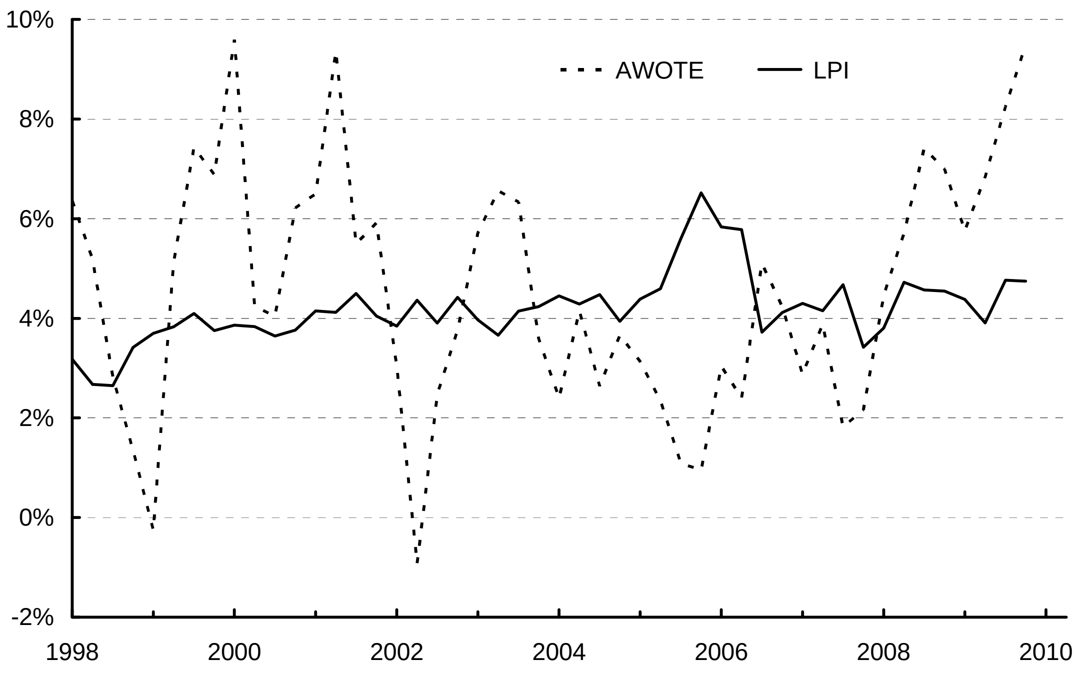
58 The AER also notes that it considers the employee structure in the base year—for which labour cost forecasts are based upon—to be efficient. The AER considers that this does not preclude a DNSP from altering the composition of its workforce throughout the regulatory control period. Indeed, the regulatory framework provides an incentive to do this should such a change result in any productivity improvements.

Accordingly, the AER supports the use of an LPI measure, as opposed to average weekly earnings, since the LPI is not affected by compositional shifts in employment. As noted by Access Economics, compositional changes such as those arising from the business cycle, the pace of recruitment and retirement, and the degree of outsourcing can all distort AWOTE as a proxy for changes in the price of labour.[59] Further, as noted in the AER's draft decision, both Access Economics and the ABS considered the LPI to be their preferred indicator of changes in wage rates.[60]

The AER also notes that average weekly earnings measures such as AWOTE are inherently more volatile than LPI measures, as shown in figure K.1. In their report to the AER, Access Economics highlighted that such volatility problems are even more prevalent in lower level, sectoral by State data.

> These [AWOTE] volatility problems become more pronounced at greater levels of disaggregation, with the difference in volatility [between LPI and AWOTE] more pronounced in the utilities sector than across all industries as a whole...
>
> As the analysis here is not merely at the sectoral level, but at the sectoral by State level, these volatility problems rapidly compound.[61]

Figure K.1 Growth in AWOTE and LPI, Australian utilities sector



Source: Australian Bureau of Statistics; AER analysis.

In contrast to the AER's considerations, both KPMG Econtech and BIS Shrapnel advocated compensating DNSPs for compositional changes in labour costs. Specifically, KPMG Econtech provided that:

59 Access Economics, *Response to the KPMG Econtech reports of July 2010*, 13 September 2010, p. 11.

60 AER, *Draft decision*, Appendix K, p. 132.

61 Access Economics, *Response to the BIS Shrapnel reports of July 2010*, 13 September 2010, pp. 10–11.

> [s]elective redundancies and graduate hiring freezes … have created changes in the composition of employment between senior and junior staff, and between support staff and fee earning staff …
>
> Consequently, compositional impacts derived from competition between businesses, and overall changes in the labour market are expected to continue to have a strong impact on the labour costs faced by employers over the forecast period.[62]

The AER, however, considers that the compositional impacts identified by KPMG Econtech appear significantly overstated. As Access Economics noted:

> … wage freezes of themselves would not influence any gap in growth between AWOTE and the LPI. That would require a change in the pattern of promotions … As the utilities were rather less affected by the GFC than most other sectors, that would seem to be a long bow.[63]

The AER further notes analysis undertaken by Access Economics that demonstrated the degree of compositional change required to explain the level of divergence between the AWOTE and LPI assessments in the utilities sector over the past year. To derive a gap equal to the current differential—9.5 per cent growth instead of 4.7 per cent growth—Access Economics noted the following:

> Say the compositional change involved firing 1 per cent of the workforce, and hiring replacements. Further, for the sake of simplicity of the example, assume that the average wage in the sector is $100,000 a year. To get a gap equal to that evident currently, the past year would have to have seen some 1,300 people earning only half the average ($50,000) sacked, with their replacements earning more than ten times that ($530,000).
>
> Moreover, there is a fundamental flaw in KPMG Econtech's arguments … if there were such compositional effects, they would also be having an impact on the productivity of the sector's workforce.
>
> After all, if the sector is firing some workers and replacing them with others earning more than ten times as much, there would be reasonable expectation that the new workers would be rather more productive than the workers they are replacing.
>
> … in other words, the argument that 'sometimes compositional change in the workforce will be important for the AER to consider' will always be overstated, because it implicitly assumes that the cost of compositional changes in the quality of the workforce are not partly or completely offset by equivalent productivity impacts.[64]

The AER agrees also with Access Economics, that:

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[62] KPMG Econtech, *Assessment of the AER's draft decision on labour cost escalation: Victoria*, 13 July 2010, p. 30

[63] Access Economics, *Response to the KPMG Econtech reports of July 2010*, 13 September 2010, p. 10.

[64] Access Economics, *Response to the KPMG Econtech reports of July 2010*, 13 September 2010, p. 10.

> [m]ore broadly, compositional effects and the resultant volatility make AWOTE a poor base for undertaking wage forecasts for the utilities sector.[65]

Having had regard to the analysis discussed above, including the information included in and accompanying the Victorian DNSPs regulatory proposals, the analysis undertaken for the AER by Access Economics, and the actual and expected capex and opex of the Victorian DNSPs during preceding regulatory control periods, the AER maintains its view in the draft decision.[66] That is, the AER considers that consistent with both the NEL and NER, labour cost escalators based on an LPI measure most reasonably reflect the labour costs that a Victorian DNSP is likely to incur.[67]

K.5.3.5 Relevant data

The Victorian DNSPs revised regulatory proposals considered that the currency of data—that is, the timeliness of data—is not a reason for rejecting a DNSP's proposed methodology for determining input cost escalators. In particular, JEN noted that:

> [i]mplicit in the AER's draft decision is that in order for a forecast to be consistent with the Rules (a realistic expectation), it must be a forecast that is generated closer to the final decision than the forecasts generated for the original or revised regulatory proposal.
>
> … The AER cannot consider a forecast that JEN puts forward as inconsistent with the Rules solely on an assumption that a better forecast will be generated if relevant inputs to the forecast are updated closer to the final decision.[68]

AER considerations

The NER requires that for the AER to accept the total of forecast capex and opex proposed by a DNSP for the regulatory control period, the AER must be satisfied that the total of forecast capex and opex reasonably reflects a realistic expectation of the cost inputs required to achieve the capex and opex objectives.[69] Given the level of uncertainty within the current economic climate, the AER has had specific regard to this criterion.

In particular the AER considers that to be satisfied to this effect, the forecasts should be based on the most recently available data.

The AER notes, however, that contrary to the intimations of the Victorian DNSPs, the timeliness of the Victorian DNSPs' forecasts was only one reason why the AER did not accept the proposed labour cost escalators. The additional reasons, including the choice of wage measure, are discussed throughout this appendix.

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65 Access Economics, *Response to the KPMG Econtech reports of July 2010*, 13 September 2010, p. 10.

66 Clauses 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(5), 6.5.7(e)(1), 6.5.7(e)(3) and 6.5.7(e)(5) of the NER.

67 The AER acknowledges that the New South Wales electricity distribution determination and Jemena Gas Networks access arrangement utilised average weekly earnings measures to forecast labour cost increases. The AER notes that the Jemena Gas Networks access arrangement was considered under different legislation, while the New South Wales electricity distribution decision did not explicitly consider this issue. Rather, the AER accepted its consultant's estimates, as agreed to by the DNSPs. The most recent Queensland and South Australian electricity distribution determinations, however, have relied upon the LPI, reflecting the views outlined above.

68 JEN, *Revised regulatory proposal*, p. 187–188.

69 Clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER.

The AER also acknowledges that SP AusNet provided the AER with updated labour cost forecasts closer to the date of the AER's final decision.[70] However, as noted previously, the AER has not accepted the Victorian DNSPs labour cost escalators for a number of reasons. For these same reasons the AER has not accepted the updated labour cost forecasts provided by SP AusNet.

K.5.3.6 Productivity

CitiPower and Powercor proposed that forecasts used to derive labour cost escalators for DNSP price review processes should not take productivity improvements into account. CitiPower and Powercor considered that this distorted the incentives for efficiency that would otherwise be created by the AER's EBSS. Both CitiPower and Powercor noted, however, that the labour, and contract and other costs escalators applied throughout their revised regulatory proposals actually incorporated productivity improvements.[71]

JEN concluded that past AER determinations did not appear to be consistent in their adoption of labour productivity adjustments. However, JEN considered this to be a secondary issue to other elements of its revised regulatory proposal.[72]

Conversely, SP AusNet supported the AER's draft decision, stating:

> SP AusNet agrees that productivity adjustments are important, and that they should be included in labour cost modelling.[73]

Submissions

The EUCV noted that the AER's draft decision supported the application of Access Economics' productivity impacts in the modelling of its wage cost growth forecasts. However, the EUCV highlighted that the AER instead applied Access Economics' labour price aggregates without productivity adjustments.[74]

The EUCV also added that previous ESCV decisions, and those of other regulators, inserted specific productivity gains into the capex and opex forecasts for labour inputs.[75]

AER considerations

Access Economics provided the AER with a series of forecast LPIs adjusted for productivity, as well as a series of forecast LPIs which are not adjusted for productivity.

In its draft decision, the AER used the unadjusted productivity LPIs provided by Access Economics. As noted above, the EUCV raised concerns with the use of the unadjusted productivity LPIs and considered that the adjusted LPIs should be used.

[70] CitiPower and Powercor also stated in their revised regulatory proposals that they would supply such updates, though none were provided to the AER. CitiPower, *Revised regulatory proposal*, p. 238; Powercor, *Revised regulatory proposal*, p. 228; SP AusNet, *Revised regulatory proposal*, p. 183.
[71] CitiPower, *Revised regulatory proposal*, p. 238; Powercor, *Revised regulatory proposal*, p. 228.
[72] JEN, *Revised regulatory proposal*, p. 180.
[73] SP AusNet, *Revised regulatory proposal*, p. 181.
[74] EUCV, Submission, 19 August 2010, p. 29.
[75] EUCV, Submission, 19 August 2010, p. 29.

The AER considers that the EUCV has raised issues that require further consideration and consultation with all interested stakeholders. The AER notes that it was not provided the EUCV's finalised submission until 7 September 2010, three weeks after the deadline for submissions of 19 August 2010, and considers sufficient time has not been available to undertake that consultation.

For these reasons, the AER maintains that, consistent with the AER's draft decision, productivity unadjusted LPIs most reasonably reflect a realistic expectation of the labour input costs required to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.[76]

In response to CitiPower's and Powercor's concerns regarding the distortion of incentives, the AER notes the lack of supporting arguments and substantive evidence in CitiPower's and Powercor's regulatory proposals as to how the productivity adjustments actually reduce the strength of the EBSS. The AER considers that the benefit to a DNSP and its incentive to reduce its opex relative to that forecast under the EBSS is not distorted by the AER's approach to labour cost escalation. That is, the opex forecast provided to the DNSPs does not impact the incremental benefit or the incentives to the DNSPs of reducing their actual opex.

K.5.3.7 Weighted average internal labour cost escalators

The approach undertaken in the AER's draft decision to develop internal labour cost escalators reflected a weighted average of the Victorian DNSPs' EGW, and clerical and administrative staff.[77] The AER was not satisfied that an internal labour cost escalator that only considered wage growth within the EGW sector accurately reflected the composition of a Victorian DNSP's internal labour force.[78]

The AER's approach was contrary to that adopted by the Victorian DNSPs, which applied a single EGW labour growth rate across all internal employees.[79]

In their revised regulatory proposals, the Victorian DNSPs noted that construction of the labour and employee earnings surveys undertaken by the ABS already captured both specialist EGW and other administrative staff. In particular, CitiPower and Powercor provided a copy of email correspondence entered into with the ABS.[80] In response to whether the AWE and LPI statistics prepared by the ABS for the EGW industry reflected the average weekly earnings and hourly rates of pay for both specialist EGW and clerical and administrative staff, the ABS advised that:

> … regardless of the type of job, if the job was selected from a businesses classified to the Electricity, Gas, Water and Waste Services industry, the jobs pay movements contributes to this industry.[81]

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76 The AER notes that the most recent Queensland and South Australian electricity distribution determinations used the Access Economics LPI series that were not adjusted for forecast productivity.

77 AER, *Draft decision*, Appendix K, p. 135.

78 AER, *Draft decision*, Appendix K, p. 134.

79 AER, *Draft decision*, Appendix K, p. 134.

80 CitiPower, *Revised regulatory proposal*, Appendices 149 and 150; Powercor, *Revised regulatory proposal*, Appendices 149 and 150.

81 CitiPower, *Revised regulatory proposal*, Appendices 149 and 150.

Submissions

EnergyAustralia noted that should the AER not apply EGW escalation rates to clerical staff, which 'may be appropriate', the AER should further investigate how the EGW index is actually collated.[82]

AER considerations

The AER's draft decision considered that developing internal labour cost escalators as a weighted average of multiple ANZSIC subdivisions was consistent with the methodology employed by the ABS. With respect to this consideration, the AER notes that the rationale behind its draft decision appears to have been misinterpreted by the Victorian DNSPs.

Specifically, the AER considered that the units model adopted by the ABS to determine the reporting structure of a business facilitates the collection of data based on the type of activity undertaken.[83] Further, the AER considered that given the administrative services operations of the Victorian DNSPs are undertaken by separate (albeit related) entities, the Victorian DNSPs should be able to report these operations separately. To the extent that the Victorian DNSPs' network management and administrative services operations would be classified to separate industries under the ANZSIC'06, the AER considered that weighted internal labour escalators best reflected the efficient cost inputs required to achieve the capex and opex objectives.

With regard to these issues the AER has reviewed the Victorian DNSPs' revised regulatory proposals and has further considered the robustness of assumptions considered in the draft decision. In particular, the AER notes that the classification of the Victorian DNSPs' administrative services entities are more likely to reflect the classification of the Victorian DNSPs' themselves, given that these administrative services entities provide labour predominantly to the Victorian DNSPs. According to the methods of classification detailed in the ANZSIC'06 release, where a unit provides the entire workforce to the client business, it is classified according to the nature of the activity being undertaken for the client business.[84]

Further, the AER notes the analysis undertaken by KPMG Econtech, and provided by CitiPower and Powercor. Specifically, KPMG Econtech stated that:

> … if the composition of Powercor and CitiPower's internal labour force (the split between asset management, PNS and CHED Services) is similar to the average for the industry, changes in internal labour costs related to movements in the labour costs for CHED Services would be adequately reflected in the AWE for the Electricity, Gas, Water and Waste Services industry.[85]

The AER considers that KPMG Econtech's comments are equally applicable to all the Victorian DNSPs.

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[82] EnergyAustralia, *Submission to the AER*, 19 August 2010, p. 8.

[83] ABS, Catalogue no. 1292.0, *Australian and New Zealand Standard Industrial Classification 2006*, pp. 497–498.

[84] ABS, Catalogue no. 1292.0, *Australian and New Zealand Standard Industrial Classification 2006*, p. 27.

[85] KPMG Econtech, *Labour cost forecasts for Powercor and CitiPower*, 13 July 2010, p. 33.

Accordingly, the AER accepts that the real labour cost escalators applied to all internal employees should be based solely on EGW labour price movements, consistent with the Victorian DNSPs' revised regulatory proposals.

K.5.3.8 Application of EBA rates

CitiPower's and Powercor's revised regulatory proposals considered that the incentives built into the regulatory regime, specifically the AER's EBSS, ensured that the Victorian DNSPs will continue to have an incentive to strongly negotiate EBA rates in the forthcoming regulatory control period.[86]

CitiPower and Powercor also considered that although the AER had stated its intention to adopt actual wage increases up until the beginning of the forthcoming regulatory control period, it had not done so.[87]

AER considerations

The AER acknowledges CitiPower's and Powercor's considerations regarding the application of EBA rates for escalating internal labour costs. The AER, however, maintains that consistent with previous regulatory decisions, it is not appropriate to uncritically apply a DNSP's current EBA rates into the forthcoming regulatory control period.[88]

As noted in its draft decision, the AER considers that applying a DNSP's EBA rates into the forthcoming regulatory control period would reduce the incentives on DNSPs to negotiate efficient labour outcomes.[89] In particular, the AER considers that accepting workplace agreements that span across regulatory control periods could provide an incentive for DNSPs to adopt an EBA that loads labour costs towards the final years of the agreement. That is, to load labour cost increases so that they occur in the forthcoming regulatory control period.

The AER also notes that the current EBAs were negotiated under a different economic climate to that which prevails today. Further, the outcomes from any specific wage negotiation, regardless of the nature of the negotiation, do not necessarily reflect efficient labour costs for the industry as a whole. Accordingly, the AER considers it unlikely that the negotiated EBAs reasonably reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives as required under the NER. The AER also notes that accepting the Victorian DNSPs' EBA rates into the forthcoming regulatory control period would represent a shift from incentive based regulation to a regulatory framework more akin to cost of service regulation. The AER does not consider that this would be consistent with the National Electricity Objective, or with providing DNSPs with effective incentives in order to promote economic efficiency with respect to the direct control network services the DNSP provides.[90]

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86 CitiPower, *Revised regulatory proposal*, p. 242; Powercor, *Revised regulatory proposal*, p. 232.
87 CitiPower, *Revised regulatory proposal*, p. 242; Powercor, *Revised regulatory proposal*, p. 232.
88 AER, *South Australian distribution determination 2010–11 to 2014–15*, Final decision, May 2010, p. 329.
89 AER, *Draft decision*, Appendix K, pp. 135–136.
90 NEL, s.7A(3).

The AER acknowledges CitiPower's and Powercor's claim that despite the AER's intention, actual wage increases up until the beginning of the forthcoming regulatory control period have not been applied.[91] Upon review, the AER recognises that it had incorrectly determined the 2010 escalator. Specifically, the AER had weighted current EBA rates with the escalators forecast by Access Economics. While the AER had intended to apply the EBA rate in full up until the beginning of the forthcoming regulatory control period, the AER acknowledges that it had not done so in the draft decision. This oversight has been amended in this final decision.

K.5.3.9 Weighted average outsourced labour cost escalators

As noted previously, for their revised regulatory proposals, CitiPower, Powercor and JEN engaged KPMG Econtech to provide an assessment of the AER's draft decision with respect to labour cost escalation. In reference to the AER's methodology for developing outsourced services labour cost escalators, KPMG Econtech stated that:

> [a]lthough the index for Property and Business Services tends to move in the same direction as the all industries index … the application of the all industries average in place of a more accurate measure of growth in industry labour costs appears to be a departure from the AER's objective of determining labour costs escalators that most reasonably reflect likely changes in labour costs over the forecast period.[92]

CitiPower and Powercor further noted that, based on the ANZSIC'06, the property and business services sector has been split into three separate classifications. Of these classifications, CitiPower and Powercor supported KPMG Econtech's recommendation that the administrative and support services category was the most appropriate series, to use together with the construction category, for the purposes of determining outsourced labour cost escalators.[93]

SP AusNet also disagreed with the AER's draft decision. SP AusNet noted that it failed to see how the AER could consider the use of a general labour costs escalator as being more reflective of the efficient costs that a prudent and efficient operator would incur, than the use of a more granular, weighted outsourced labour costs escalator.[94]

AER considerations

The AER's draft decision considered that the impact of using general labour costs as a proxy for the property and business services sector would be marginal. While the AER maintains the view that the impact would be marginal, it accepts that outsourced labour cost escalators based on an average of the construction, and administrative and support services classifications are likely to provide a better reflection of the efficient costs that a prudent and efficient operator would be likely to incur over the forthcoming regulatory control period.

As previously noted, however, the AER has not accepted the labour cost escalators proposed by the Victorian DNSPs. Instead, the AER has substituted the labour cost forecasts provided by its consultant, Access Economics. The AER considers these

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91 CitiPower, *Revised regulatory proposal*, p. 242; Powercor, *Revised regulatory proposal*, p. 232.
92 KPMG Econtech, *Assessment of the AER's draft decision on labour cost escalation: Victoria*, 13 July 2010, p. 28.
93 CitiPower, *Revised regulatory proposal*, p. 244; Powercor, *Revised regulatory proposal*, p. 234.
94 SP AusNet, *Revised regulatory proposal*, p. 183.

forecasts, based on a LPI measure for the reasons discussed in section K.5.3.4, most reasonably reflect the labour costs that a Victorian DNSP is likely to incur.

The resultant outsourced labour cost escalators are provided in table K.12.

K.5.3.10 Construction labour cost forecasts

The AER's draft decision noted that it had utilised the CFC forecasts in the development of the outsourced services labour cost escalators.

JEN's revised regulatory proposal, however, noted that the CFC forecasts are not forecasts of labour costs or wages. Further, JEN noted that the CFC forecasts are not state specific, but apply to Australia as a whole. JEN supported these considerations with analysis undertaken by KPMG Econtech, which concluded that the AER had 'incorrectly applied output price forecasts from the CFC website, in place of using wage cost forecasts'.[95]

AER considerations

The AER acknowledges the analysis undertaken by KPMG Econtech and accepts JEN's comments regarding the inappropriate use of CFC forecasts as a proxy for forecasting labour cost movements.

Accordingly, the AER has substituted the CFC forecasts with the construction specific LPI provided by Access Economics. The AER considers these forecasts, based on a LPI measure for the reasons discussed in section K.5.3.4, most reasonably reflect the labour costs that a Victorian DNSP is likely to incur. Further, the AER is satisfied that this change provides outsourced labour cost escalators that are consistent with capex and opex allowances that reasonably reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives.

K.5.3.11 AER conclusion

The AER is not satisfied that the labour cost escalation forecasts proposed by the Victorian DNSPs are consistent with a total capex and opex forecast that reasonably reflects a realistic expectation of the cost inputs required to achieve the capex and opex objectives.

The AER has substituted the escalators proposed by the Victorian DNSPs with the escalators in tables K.11 and K.12. The AER considers these adjustments are the minimum necessary for the AER to be satisfied that these escalators are consistent with a total capex and opex forecast that reasonably reflects the capex and opex criteria.[96] In coming to this view, the AER has had regard to the information included in and accompanying the Victorian DNSPs proposals, submissions received by EnergyAustralia and the EUCV, analysis undertaken for the AER by Access Economics and by the AER that was published before this distribution determination was made in its final form, and the actual and expected opex of the Victorian DNSPs during preceding regulatory control periods.[97]

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95 JEN, *Revised regulatory proposal*, pp. 182–183.

96 Specifically, clauses 6.5.6(c) (3) and 6.5.7(c) (3) of the NER.

97 Clauses 6.5.6(e)(1), 6.5.6(e)(2), 6.5.6(e)(3), 6.5.6(e)(5), 6.5.7(e)(1), 6.5.7(e)(2), 6.5.7(e)(3) and 6.5.7(e)(5) of the NER.

Table K.11 AER conclusion on internal labour real cost escalators (per cent)

	2010	2011	2012	2013	2014	2015
CitiPower	1.3	1.1	2.0	2.4	3.3	2.2
Powercor	1.3	1.1	2.0	2.4	3.3	2.2
JEN	1.2	1.1	2.0	2.4	3.3	2.2
SP AusNet	1.5	1.1	2.0	2.4	3.3	2.2
United Energy	0.5	1.3	2.0	2.4	3.3	2.2

Source: AER analysis.

Table K.12 AER conclusion on outsourced services labour real cost escalators (per cent)

	2010	2011	2012	2013	2014	2015
CitiPower	-0.3	0.8	1.8	2.4	3.1	2.1
Powercor	-0.3	0.8	1.8	2.4	3.1	2.1
JEN	-0.3	0.8	1.8	2.4	3.1	2.1
SP AusNet	-0.3	0.8	1.8	2.4	3.1	2.1
United Energy	-0.3	0.8	1.8	2.4	3.1	2.1

Source: AER analysis.

K.5.4 Application of real cost escalators

K.5.4.1 AER draft decision

The AER provided each of the Victorian DNSPs the labour and materials cost escalators determined in the draft decision and requested that they escalate their initial capex and opex proposals by these escalators. Using the amount of real cost escalation, as forecast by the Victorian DNSPs, the AER determined weighted capex and opex real escalation rates that it used to escalate forecast capex and opex for each of the DNSPs.[98]

To escalate United Energy's total forecast opex the AER used a weighted average of the weighted opex escalation rates for CitiPower, Powercor, JEN and SP AusNet.[99]

The AER noted that SP AusNet's weighted capex real escalation rates were significantly higher than the other DNSPs. In the absence of sufficient information to determine the cause of this discrepancy the AER used the weighted capex escalation rates for Powercor, the distribution network most similar to SP AusNet.[100]

98 AER, *Draft decision*, Appendix K, pp. 145–153.
99 AER, *Draft decision*, Appendix K, pp. 146–147.
100 AER, *Draft decision*, Appendix K, pp. 147–148.

The AER noted that it would require the Victorian DNSPs to provide the weightings of each of the labour and materials escalators in their capex programs. The AER stated that it would use this information in determining the amount or real cost escalation for each of the Victorian DNSPs in its final decision.[101]

The AER did not apply real cost escalation to opex step changes.

K.5.4.2 Victorian DNSP revised regulatory proposals

The AER notes that CitiPower, Powercor, JEN and SP AusNet all applied real cost escalators to their step changes.[102]

The AER also notes that only SP AusNet provided the weightings of each of the labour and materials escalators in its capex program as required by a revised regulatory information notice issued by the AER.

K.5.4.3 AER considerations

The AER notes that in the draft decision it did not apply real cost escalation to opex step changes. However, CitiPower, Powercor, JEN and SP AusNet all applied real cost escalators to opex step changes in their revised regulatory proposals. The AER has reconsidered its approach to the escalation of opex step changes and now considers that the approach adopted in the draft decision treated base opex and opex step changes inconsistently. The AER considers that in order to provide a total opex forecast that reasonably reflects a realistic expectation of the cost inputs required to achieve the operating expenditure objectives, opex step changes should be escalated for forecast real price movements.

Consistent with the approach adopted in the draft decision, the AER provided each of the Victorian DNSPs the labour and materials cost escalators determined above, and requested that they escalate their revised capex and opex proposals by these escalators. The Victorian DNSPs advised the AER that applying the labour and materials escalators determined by the AER, and using updated equipment escalation factors determined by SKM, escalated their capex and opex proposals by the amounts outlined in tables K.13 and K.14.

[101] AER, *Draft decision*, Appendix K, p. 149.

[102] CitiPower, *Revised regulatory proposal*, pp. 211–214; Powercor, *Revised regulatory proposal*, pp. 200–202; JEN, response to information requested on 11 August 2010, 13 August 2010; SP AusNet, response to information requested on 11 August 2010, 18 August 2010.

Table K.13 Victorian DNSP weighted opex real cost escalation rates (per cent)

	2011	2012	2013	2014	2015
CitiPower	0.8	2.4	4.3	6.8	8.4
Powercor	0.9	2.4	4.4	7.1	8.8
JEN	1.1	2.2	3.6	5.5	6.9
SP AusNet	0.6	2.1	3.9	6.2	7.4
United Energy	0.3	0.5	0.9	1.2	1.5

Note: The weighted opex escalation rates represent the amount of real cost escalation, as forecast by the Victorian DNSPs using the labour and materials real cost escalators determined by the AER, as a percentage of proposed standard control opex, exclusive of scale escalation, real cost escalation and related party margins.

Source: AER analysis; CitiPower, response to information requested on 12 October 2010, 15 October 2010; Powercor, response to information requested on 12 October 2010, 15 October 2010; JEN, response to information requested on 12 October 2010, 18 October 2010; SP AusNet, response to information requested on 12 October 2010, 18 October 2010; United Energy, response to information requested on 12 October 2010, 18 October 2010.

The AER notes that opex is comprised of largely labour costs. When compared against the internal and external labour escalation rates determined by the AER these weighted opex escalation rates appear reasonable, except for United Energy.

The AER notes that the weighted opex escalation rate for United Energy is significantly lower than the other Victorian DNSPs. This reflects the fact that United Energy used a different approach to forecast its opex requirements during the forthcoming regulatory control period. United Energy did not base its opex proposal on a single year of historic opex. Rather it based its opex proposal on the outcomes of a competitive tender process, to which it did not apply any real cost escalation.[103]

For the reasons discussed in appendix I, the AER is not satisfied that the opex proposed by United Energy reasonably reflects the opex criteria, including the opex objectives. The AER has determined a total forecast opex amount for United Energy which is based on its actual opex in 2009, rather than the outcomes of a tender process. Given this, the AER considers that the weighted opex escalation rates for United Energy do not reflect the forecast real cost increases because United Energy did not escalate their tendered opex. That is, the AER considers that real cost escalators should be applied to the whole of United Energy's forecast opex. For the purpose of escalating United Energy's total forecast opex for real cost increases, the AER is satisfied that a weighted average of the weighted opex escalation rates for CitiPower, Powercor, Jemena and SP AusNet is consistent with a total forecast opex that reasonably reflects the opex criteria, and in particular a realistic expectation of the cost inputs required to achieve the operating expenditure objectives.

[103] United Energy, *Revised regulatory proposal*, pp. 37–38.

Table K.14 Victorian DNSP weighted capex real cost escalation rates (per cent)

	2011	2012	2013	2014	2015
CitiPower	3.3	5.2	7.4	10.3	12.5
Powercor	3.2	4.8	6.6	9.1	10.9
JEN	–0.5	0.1	1.0	2.3	3.0
SP AusNet	11.6	11.8	13.4	13.6	14.7
United Energy	3.0	2.8	2.1	3.3	3.7

Note: The weighted capex escalation rates represent the amount of real cost escalation, as forecast by the Victorian DNSPs using the labour and materials real cost escalators determined by the AER, as a percentage of proposed total gross capex, exclusive of indirect overheads, real cost escalation and related party margins.

Source: AER analysis; CitiPower, response to information requested on 12 October 2010, 15 October 2010; Powercor, response to information requested on 12 October 2010, 15 October 2010; JEN, response to information requested on 12 October 2010, 18 October 2010; SP AusNet, response to information requested on 12 October 2010, 18 October 2010; United Energy, response to information requested on 12 October 2010, 18 October 2010.

The AER notes that the weighted capex real cost escalation rates for SP AusNet are higher than for the other Victorian DNSPs, particularly in the earlier years of the forthcoming regulatory control period. SP AusNet was the only Victorian DNSP to provide the AER with the weightings of each of the materials escalators in their capex programs, outlined in table K.15.

Table K.15 SP AusNet capex labour and materials weightings (per cent)

Escalator	Weighting
Internal labour	8.1
Contract labour	37.3
Materials	
Aluminium	3.9
Copper	8.6
Steel	11.1
Crude oil	2.1
Manufacturing	16.7
Direct overheads	–
Indirect overheads	12.2

Source: SP AusNet, revised RIN template.

Applying these labour and materials weights to the labour and materials escalators determined above, and those in SP AusNet's revised RIN template, yields the weighted capex escalation rates in table K.16.

Table K.16 SP AusNet weighted capex real cost escalation rates using SP AusNet labour and materials weightings (per cent)

2011	2012	2013	2014	2015
9.7	10.3	11.2	12.3	12.9

Source: AER analysis; SP AusNet, revised RIN template.

The AER notes that these weighted capex real cost escalation rates are similar to those in table K.14, albeit a little lower. However, the AER notes that the weighted capex escalation rates in table K.14 are based on a more granular calculation of the impact of real cost escalators on SP AusNet's capex than the weighted rates in table K.16. Consequently the AER is satisfied that the weighted real cost escalation rates in table K.14 are consistent with a total forecast capex that reasonably reflects the capex criteria and, in particular, reasonably reflect a realistic expectation of the cost inputs required to achieve the operating expenditure objectives.

Considering this, the AER is satisfied that the weighted capex escalation rates for the Victorian DNSPs, based on the capex proposals escalated for the impact of the labour and materials real cost escalators determined by the AER, are consistent with a total forecast capex that reasonably reflects the capex criteria, and in particular a realistic expectation of the cost inputs required to achieve the capital expenditure objectives.

K.6 AER conclusion

For the reasons discussed above, the AER considers its weighted capex and opex real cost escalators, as outlined in tables K.17, K.18, K.19, K.20 K.21 and K.22 are consistent with total a forecast capex and a total forecast opex that reasonably reflect the capex and opex criteria, and in particular reasonably reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives

This appendix has assessed the proposed allowance for real cost escalation which is one component of each Victorian DNSP's proposed total forecast capex and opex. The AER considers that the proposed allowance assessed in this appendix is consistent with the requirement in clause 6.5.6(c) and 6.5.7(c) of the NER that the total forecast capex and opex reasonably reflects the capex and opex criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capex and opex.

That constituent decision, which should be read together with this appendix, is discussed in chapters 7 and 8.

Table K.17 AER conclusion on weighted opex real cost escalation rates (per cent)

	2011	2012	2013	2014	2015
CitiPower	0.8	2.4	4.3	6.8	8.4
Powercor	0.9	2.4	4.4	7.1	8.8
JEN	1.1	2.2	3.6	5.5	6.9
SP AusNet	0.6	2.1	3.9	6.2	7.4
United Energy	0.8	2.2	4.1	6.5	7.9

Source: AER analysis; CitiPower, response to information requested on 12 October 2010, 15 October 2010; Powercor, response to information requested on 12 October 2010, 15 October 2010; JEN, response to information requested on 12 October 2010, 18 October 2010; SP AusNet, response to information requested on 12 October 2010, 18 October 2010.

Table K.18 AER conclusion on weighted capex real cost escalation rates, CitiPower (per cent)

	2011	2012	2013	2014	2015	Total
System assets						
Demand Related						
Reinforcement	3.1	5.6	7.8	11.0	13.0	7.8
Gross Demand Connections	4.4	6.0	8.0	10.7	12.8	8.4
Non-Demand Related						
Reliability and quality maintained	3.2	5.1	7.4	10.8	13.3	8.2
Reliability and quality improvements						
Environmental, safety and legal obligations	2.4	4.4	6.9	10.4	13.0	7.4
Sub-total—system assets	**3.6**	**5.6**	**7.7**	**10.8**	**13.0**	**8.1**
Non-system assets						
SCADA & network control	1.1	2.9	5.1	8.3	10.7	5.6
Non-network general—IT	1.0	2.3	3.3	5.9	7.0	4.1
Non-network general—other	0.4	1.8	3.8	6.4	8.1	4.1
Sub-total—non-system assets	**0.9**	**2.3**	**3.9**	**6.5**	**8.1**	**4.4**
Total Gross Direct Capex	**3.3**	**5.2**	**7.4**	**10.3**	**12.5**	**7.7**

Source: AER analysis; CitiPower, response to information requested on 12 October 2010, 15 October 2010.

Table K.19 AER conclusion on weighted capex real cost escalation rates, Powercor (per cent)

	2011	2012	2013	2014	2015	Total
System assets						
Demand Related						
Reinforcement	4.3	5.8	7.7	10.2	11.9	8.2
Gross Demand Connections	4.0	5.5	7.4	10.0	11.7	7.7
Non-Demand Related						
Reliability and quality maintained	3.0	4.9	7.0	10.0	12.1	7.3
Reliability and quality improvements						
Environmental, safety and legal obligations	3.0	4.7	6.8	9.7	11.6	7.2
Sub-total—system assets	**3.7**	**5.3**	**7.3**	**10.0**	**11.9**	**7.7**
Non-system assets						
SCADA & network control	1.0	2.5	4.3	7.0	8.8	4.7
Non-network general—IT	1.0	2.3	3.3	5.9	6.9	4.0
Non-network general—other	0.1	0.5	0.9	1.6	2.0	1.0
Sub-total—non-system assets	**0.7**	**1.6**	**2.5**	**4.6**	**5.3**	**3.0**
Total Gross Direct Capex	**3.2**	**4.8**	**6.6**	**9.1**	**10.9**	**6.9**

Source: AER analysis; Powercor, response to information requested on 12 October 2010, 15 October 2010.

Table K.20 AER conclusion on weighted capex real cost escalation rates, JEN (per cent)

	2011	2012	2013	2014	2015	Total
System assets						
Demand Related						
Reinforcement	–1.1	–0.2	0.8	2.5	3.4	1.2
Gross Demand Connections	–1.8	–1.2	–0.6	0.3	0.8	–0.4
Non–Demand Related						
Reliability and quality maintained	–0.7	–0.2	0.6	2.2	2.4	1.0
Reliability and quality improvements						
Environmental, safety and legal obligations	0.1	1.0	2.6	5.1	6.6	3.3
Sub–total—system assets	**–1.0**	**–0.3**	**0.7**	**2.2**	**2.9**	**1.1**
Non–system assets						
SCADA & network control	–	–	–	–	–	–
Non–network general—IT	0.9	2.1	3.6	5.6	7.1	2.8
Non–network general—other	–	–	–	–	–	–
Sub–total—non–system assets	**0.4**	**0.9**	**2.3**	**3.1**	**3.5**	**1.4**
Total Gross Direct Capex	**–0.5**	**0.1**	**1.0**	**2.3**	**3.0**	**1.1**

Source: AER analysis; JEN, response to information requested on 12 October 2010, 18 October 2010.

Table K.21 AER conclusion on weighted capex real cost escalation rates, SP AusNet (per cent)

	2011	2012	2013	2014	2015	Total
System assets						
Demand Related						
Reinforcement	12.0	12.2	14.7	15.1	15.7	14.0
Gross Demand Connections	16.3	16.5	16.9	17.1	16.8	16.7
Non-Demand Related						
Reliability and quality maintained	11.8	12.3	13.0	14.1	14.6	13.2
Reliability and quality improvements						
Environmental, safety and legal obligations	1.8	2.5	3.4	4.7	5.5	3.6
Sub-total—system assets	**13.5**	**13.6**	**14.8**	**15.3**	**15.5**	**14.6**
Non-system assets						
SCADA & network control	0.7	1.7	3.0	4.7	5.9	4.0
Non-network general—IT	0.7	1.7	3.0	4.7	5.9	2.9
Non-network general—other	0.1	0.3	0.6	0.9	1.2	0.6
Sub-total—non-system assets	**0.7**	**1.6**	**2.7**	**4.3**	**5.0**	**2.7**
Total Gross Direct Capex	**11.6**	**11.8**	**13.4**	**13.6**	**14.7**	**13.0**

Source: AER analysis; SP AusNet, response to information requested on 12 October 2010, 18 October 2010.

Table K.22 AER conclusion on weighted capex real cost escalation rates, United Energy (per cent)

	2011	2012	2013	2014	2015	Total
System assets						
Demand Related						
Reinforcement	5.9	5.0	3.4	5.2	5.4	4.9
Gross Demand Connections	6.2	5.4	2.8	4.1	4.6	4.6
Non-Demand Related						
Reliability and quality maintained	0.3	0.9	1.6	2.5	2.9	1.6
Reliability and quality improvements						
Environmental, safety and legal obligations	1.9	2.9	2.0	1.5	1.6	2.1
Sub-total—system assets	**3.5**	**3.5**	**2.5**	**3.7**	**3.9**	**3.4**
Non-system assets						
SCADA & network control	–	–	–	–	–	–
Non-network general—IT	–	–	–	–	–	–
Non-network general—other	–	–	–	–	–	–
Sub-total—non-system assets	**–**	**–**	**–**	**–**	**–**	**–**
Total Gross Direct Capex	**3.0**	**2.8**	**2.1**	**3.3**	**3.7**	**2.9**

Source: AER analysis; United Energy, response to information requested on 12 October 2010, 18 October 2010.

L Operating expenditure step changes

As set out in the operating expenditure chapter (chapter 7), each Victorian DNSP proposed an allowance for operating expenditure step changes as a component of their total proposed forecast operating expenditure for the 2011–15 regulatory control period.

The assessment of operating expenditure step changes is relevant to the AER's assessment of the total of the forecast operating expenditure included in each DNSP's building block proposal for the regulatory control period. Clause 6.5.6(c) of the NER states that the AER must accept the forecast of required operating expenditure of a DNSP 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]

> (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 opex objectives are contained in clause 6.5.6(a) of the NER. A DNSP is required by clause 6.5.6(a) of the NER to include in its building block proposal the total forecast opex for the regulatory control period that the DNSP considers is required to:

> (1) meet or manage the expected demand for standard control services over that period;
>
> (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
>
> (3) maintain the quality, reliability and security of supply of standard control services; and
>
> (4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In deciding whether or not the AER is satisfied that the total opex forecast reasonably reflects the opex criteria, the AER must have regard to the opex factors in clause 6.5.6(e) of the NER. If the AER is not satisfied that the total opex forecast reasonably reflects the opex criteria, the AER must not accept the opex forecast.[2] If the AER does not accept a forecast opex proposal in accordance with clause 6.5.6(d), clause 6.12.1(4)(ii) of the NER states that:

> The AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required operating expenditure for the regulatory control period that the AER is satisfied

[1] NER, clause 6.5.6(c).
[2] NER, clause 6.5.6(d).

reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors.

The AER's approach under the NER to its assessment of the total proposed forecast operating expenditure (opex), which comprises base year opex, scale escalation, real input cost escalation and step changes, is set out in chapter 7.

As outlined in chapter 7, the AER considers that the provision of an allowance for step change costs is consistent with the operating expenditure objectives.

This appendix assesses the proposed allowance and the level of efficient expenditure for operating expenditure step changes which a prudent operator, in the actual circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the operating expenditure objectives.

This assessment in turn raises issues regarding the reasons for, and the efficient level of, the incremental costs (to those already in the base year) that the Victorian DNSPs have proposed to meet the opex objectives. The AER considers that the operating expenditure factors at clauses 6.5.6(e)(1), (2),(5), (7) and (10) are particularly relevant to this assessment. The AER also recognises that other instruments, industry standards and previous regulatory decisions are relevant to this assessment.

The AER also notes that all step change amounts in this appendix are exclusive of real cost escalation. The application of real cost escalation to step changes, in addition to base opex, is discussed in appendix K.

As discussed in the introduction to chapter 7, in assessing the Victorian DNSPs' proposed step changes, the AER has since reconsidered its approach and decided not to apply the Wilson Cook criteria which it applied in the NSW/ACT distribution determination. Instead, the AER's assessment has been made against the relevant requirements of the NEL and the NER, namely the opex criteria, the opex factors, the NEO and the RPP.

L.1 AER draft decision

After determining the base year opex—as discussed in chapter 7—the AER assessed the Victorian DNSPs proposals for additional costs arising from new (or changed) legislative obligations or changes in the operating environment (termed 'step changes'). The AER noted that for the purpose of this assessment, the reference to legislative obligations was intended to encompass all regulatory obligations whether imposed by legislation or another regulatory instrument, such as a licence, code or price determination.

The AER noted that the opex criteria require that the total of the forecast opex for the regulatory control period reasonably reflect the efficient costs and the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives.[3] In assessing the Victorian DNSPs' proposals, the AER determined that it must therefore be satisfied that any proposed opex step changes

[3] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2).

reasonably reflect the opex criteria, including the opex objectives.[4] In coming to its view, the AER stated that it had regard to the opex factors, specifically:

(4) benchmark opex that would be incurred by an efficient DNSP over the regulatory control period

(5) the actual and expected opex of the DNSP during any preceding regulatory control periods

(7) the substitution possibilities between opex and capex[5]

In assessing the Victorian DNSPs proposed step changes, the AER in the first instance had regard to changes in the regulatory obligations and subsequently changes in the operating environment. The AER noted that consistent with its approach in the New South Wales electricity distribution final determination, the AER assessed whether the proposed opex was prudent and efficient. In determining whether the opex was prudent and efficient, the AER had regard to whether the proposals had appropriately quantified all costs savings and benefits.

Based on the AER's assessment of the Victorian DNSPs regulatory proposals, the draft decision accepted approximately $45 million ($2010) of the proposed $293 million ($2010) step changes. The step changes determined in the draft decision, and added to the base opex, are outlined in table L.1.

Table L.1 AER draft decision on step changes to opex for 2011–15 ($'m, 2010)

Step changes	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
Electricity safety regulation related	1.2	–17.1	0.9	5.3	1.4	**–8.2**
Insurance	–	–	–	15.0	3.5	**18.5**
National framework of distribution network planning & expansion	2.7	4.3	0.5	1.9	1.4	**10.8**
Customer communications	0.3	0.7	2.5	–	2.3	**5.9**
Regulatory submission costs	1.7	4.0	3.5	–	2.2	**11.4**
DNSP specific	–	–	3.2	2.8[a]	–	**6.0**
Total	**6.0**	**–8.1**	**10.7**	**25.0**	**10.9**	**44.5**

Note: Totals may not add due to rounding.
(a) This reflects a reallocation of corporate costs.
Source: AER, *Draft decision*, Appendix L, p. 240.

4 NER, clauses 6.5.6(c), 6.5.6(a).
5 NER, clause 6.5.6(e)

The step changes determined for each of the Victorian DNSPs in the draft decision, by year, are outlined in table L.2.

Table L.2 AER draft decision on step changes to opex by year, all Victorian DNSPs, 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	1.2	0.7	0.9	1.6	1.5	**6.0**
Powercor	–1.8	–2.5	–2.5	–0.5	–0.8	**–8.1**
JEN	1.9	1.5	1.2	3.6	2.5	**10.7**
SP AusNet	4.4	4.1	4.9	5.7	6.0	**25.0**
United Energy	2.2	1.6	1.6	3.0	2.4	**10.9**

Note: Totals may not add due to rounding.
Source: AER, *Draft decision*, Appendix L, p. 240.

L.2 Victorian DNSP revised regulatory proposals

Both CitiPower and Powercor did not agree with the opex step changes of $6.0 million ($2010) and –$8.1 million ($2010) respectively determined in the AER's draft decision.[6] They proposed step changes of $49.0 million ($2010) and $160.6 million ($2010) for the forthcoming regulatory control period.[7] Both CitiPower and Powercor incorporated the AER's draft decision on step changes for:

- regulatory submission costs
- self insurance
- climate change
- Electricity Safety (Management) Regulations 2009
- national framework for distribution network planning and expansion
- customer charter.[8]

However, they did not agree with the AER's draft decision for step changes relating to:

- insurance
- Electricity Safety (Electric Line Clearance) Regulations 2010

6 CitiPower, *Revised regulatory proposal*, pp. 40–41, 173–214; Powercor, *Revised regulatory proposal*, pp. 38–39, 162–202.
7 CitiPower, *Revised regulatory proposal*, p. 210; Powercor, *Revised regulatory proposal*, p. 200.
8 CitiPower, *Revised regulatory proposal*, p. 177; Powercor, *Revised regulatory proposal*, pp. 166–167.

- at risk townships project (Powercor only)
- West Melbourne terminal station demand management program (CitiPower only).[9]

Further, CitiPower and Powercor raised the issue that the AER had not considered their proposed step change for communications in extreme supply events in the AER's draft decision.[10]

In addition, CitiPower and Powercor proposed five additional step changes in their respective revised proposals that they claimed have arisen since their initial proposal or have arisen out of the AER's draft decision.[11]

Jemena Electricity Networks (JEN) did not agree with the allowance of $10.7 million ($2010) in the AER's draft decision for opex step changes.[12] JEN forecast an allowance of $57.3 million ($2010) for the forthcoming regulatory control period in its revised regulatory proposal.[13] JEN stated that its revised proposal reflects:

- accepting the AER's draft decision for 32 step change items
- revising the value or supporting information for the remaining 28 original items
- quantifying the cost of two new step changes that arise due to new obligations established by the AER's draft decision.[14]

JEN noted that the two new proposed step changes related to the AER's draft decision on tariff reassignment requirements and annual monitoring and compliance reporting.[15]

Similarly, SP AusNet did not agree with the allowance of $25.0 million ($2010) in the AER's draft decision for opex step changes.[16] SP AusNet's revised regulatory proposal forecast an allowance of $194.7 million ($2010) for the forthcoming regulatory control period.[17]

SP AusNet incorporated the AER's draft decision on step changes for:

- increased bushfire insurance

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9 CitiPower, *Revised regulatory proposal*, pp. 178, 189–202; Powercor, *Revised regulatory proposal*, pp. 167, 179–191.

10 CitiPower, *Revised regulatory proposal*, pp. 203–204; Powercor, *Revised regulatory proposal*, pp. 168, 192–195.

11 CitiPower, *Revised regulatory proposal 2011–1*5, 21 July 2010, pp. 41, 174, 178, 186–189, 204–209; Powercor, *Revised regulatory proposal 2011–15*, 21 July 2010, pp. 39, 162–163, 168, 176–178, 193–197.

12 JEN, *Revised regulatory proposal*, pp. 116–117; JEN, *Revised regulatory proposal*, Appendix 7.2, 20 July 2010.

13 JEN, *Revised regulatory proposal*, 21 July 2010, p. 116.

14 JEN, *Revised regulatory proposal*, 21 July 2010, p. 116.

15 JEN, *Revised regulatory proposal*, Appendix 7.2, pp. 71–74.

16 SP AusNet, *Revised regulatory proposal*, pp. 200–256.

17 SP AusNet, *Revised regulatory proposal*, p. 256.

- climate change
- private overhead electric line (POEL) inspection program.[18]

However, SP AusNet did not agree with the AER's draft decision on the remaining opex step changes. In addition, SP AusNet proposed eight additional step changes in its revised regulatory proposal which it claimed have either been updated with more up to date information, arisen since its initial proposal or have arisen out of the AER's draft decision.[19]

United Energy did not agree with the allowance of $10.9 million ($2010) in the AER's draft decision for opex step changes.[20] United Energy's revised regulatory proposal forecast an allowance of $81.0 million ($2010) for the forthcoming regulatory control period.[21]

United Energy incorporated the AER's draft decision for step changes relating to an insurance premium increase and RIT-D requirements as well as providing a revised allowance for the step change relating to line clearances.[22]

United Energy did not agree with the AER's draft decision on the remaining opex step changes. As with the majority of the other Victorian DNSPs, United Energy also proposed two new opex step changes relating to tariff reassignment requirements and annual monitoring and compliance reporting.[23]

The Victorian DNSPs also raised concerns regarding the AER's approach to assessing opex step changes in the draft decision, stating that the AER had:

- applied opex step change criteria across jurisdictions inconsistently
- interpreted the NER and the NEL erroneously
- applied the opex step change criteria within the draft decision inconsistently.[24]

L.3 Submissions

The AER received submissions from a range of stakeholders, including:

- Energy Response, which considered that the Victorian DNSPs' proposed demand management step changes represented a reasonable first step towards exploring the potential of demand side response and other non-network solutions[25]

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18 SP AusNet, *Revised regulatory proposal*, p. 256.
19 SP AusNet, *Revised regulatory proposal*, p. 256.
20 United Energy, *Revised regulatory proposal*, pp. 85–96.
21 United Energy, *Revised regulatory proposal*, p. 96.
22 United Energy, *Revised regulatory proposal*, pp. 89, 90, 95.
23 United Energy, *Revised regulatory proposal*, p. 95.
24 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 12–14; SP AusNet, *Revised regulatory proposal*, pp. 201–210.
25 Energy Response, Submission, 17 August, 2010.

- EnergyAustralia, who considered that the AER had applied criteria in the assessment of opex step changes that do not reflect the opex criteria in the NER, and had rejected expenditure that would otherwise satisfy the criteria[26]
- EziKey Group, trading as WireAlert, in support of JEN's proposed step change to implement a pilot trial of neutral condition monitors[27]
- Grid Australia, who considered that the AER had applied criteria for the approval of opex step changes that were too narrow to deliver efficient costs[28]
- JEN, which noted that it was reviewing its forecast opex step change for compliance with new electricity safety regulations[29]
- Total Environment Centre, which considered that the AER failed to adequately assess the Victorian DNSPs' proposed non-network alternative step changes[30]
- Visy, which considered that the AER was correct to only accept clearly defined opex step changes.[31]

L.4 Consultant review

Nuttall consulting, at the request of the AER, reviewed the following opex step changes:

- Electricity Safety (Electric Line Clearance) Regulations
- West Melbourne terminal station (CitiPower)
- 'at risk township' protection plans (Powercor)
- IT opex (JEN and SP AusNet)
- opex/capex balance (JEN)
- power cable test program (SP AusNet)
- condition monitoring (SP AusNet)
- power transformer refurbishment (SP AusNet)
- substation earthing systems (SP AusNet)
- substation site cleanup (SP AusNet)
- substation civil infrastructure works (SP AusNet)

26 EnergyAustralia, Submission, 19 August 2010, pp. 14–16.
27 EziKey Group Pty Ltd, Submission, August 2010.
28 Grid Australia, Submission, 19 August 2010,
29 JEN, Submission, 19 August 2010,
30 Total Environment Centre, Submission, 24 August 2010, pp. 3–4.
31 Visy, Submission, 19 August 2010, pp. 2–3.

- substation fire systems (SP AusNet)
- process and configuration management (SP AusNet)
- quality of supply (SP AusNet)
- demand management initiatives (SP AusNet and United Energy)
- zone substation power quality metering maintenance (United Energy)
- zone substation secondary spares maintenance (United Energy)
- annual monitoring and compliance reporting (CitiPower, Powercor, JEN and United Energy).[32]

L.5 Issues and AER considerations

L.5.1 Electricity safety regulations

The Victorian DNSPs included in their revised regulatory proposals step changes for the changes to the electrical safety regulatory framework, including the:

- Electricity Safety (Management) Regulations 2009
- Electricity Safety (Electric Line Clearance) Regulations 2010
- Electricity Safety (Bushfire Mitigation) Regulations 2003.

The AER notes that, subsequent to the draft decision, the AER met with ESV and the Victorian DNSPs to establish a coordinated assessment process for safety related expenditure.

The process, established by the AER and ESV working conjointly, reviewed proposed expenditures, established whether safety was a primary driver of the proposed expenditure and if so, what ESV's view was as to the appropriate volume and timing of the proposed activity. ESV's advice to the AER is documented in its report dated 18 October 2010.[33] The AER has taken into account this advice in reaching its own view of the applicable volumes of each activity listed therein.

L.5.1.1 Electricity Safety (Management) Regulations 2009

AER draft decision

In the draft decision, the AER separated the costs of complying with the new electrical safety regulatory framework into process compliance costs and substantive compliance costs. Process compliance costs are the costs borne by the Victorian DNSPs to submit and maintain electricity safety management schemes (ESMSs) in accordance with the *Electricity Safety Act 1998* and the Electricity Safety

[32] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals,* 22 October 2010, Appendices F and G.

[33] ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010.

(Management) Regulations 2009. Substantive compliance costs are the costs of operating and maintaining a network in accordance with an approved ESMS.[34]

Only JEN and United Energy proposed step changes for ESMS process compliance costs. The AER considered that the step changes proposed by JEN and United Energy for ESMS process compliance costs were tasks that these businesses should be currently undertaking. Consequently, the AER considered that JEN and United Energy had not demonstrated that additional opex to that expended in the base year was required to comply with the process requirements of the Electricity Safety (Management) Regulations 2009.[35]

The AER noted that none of the Victorian DNSPs provided any evidence from ESV that they would need to include in their ESMSs any new or increased activities for their ESMSs to be assessed as adequate. The AER considered that if an ESMS could be assessed as adequate without requiring a particular new or increased activity then that activity was not a regulatory requirement.[36]

Victorian DNSP revised regulatory proposals

CitiPower and Powercor accepted the AER's decision to not provide a step change for the costs of complying with the Electricity Safety (Management) Regulations and that any additional costs would be borne in the 2006–10 regulatory period.[37]

JEN stated that section 107 of the Electricity Safety Act requires it to submit a revised ESMS to ESV under certain circumstances, which would impose new costs. JEN also stated that section 108 of the Electricity Safety Act requires it to submit a revised ESMS every five years, which would impose costs on it in the forthcoming regulatory control period.[38] JEN also stated that the new regulatory framework effectively requires it to 'prove' its compliance with its ESMS.[39]

SP AusNet proposed two step changes, not included in it initial regulatory proposal, for substantive compliance costs associated with its ESMS. These reflected:

1. increased replacement of conductor ties[40]
2. enhanced asset inspection programs.[41]

Consultant review

In its review of unit costs for the safety related work considered appropriate by ESV, Nuttall Consulting stated the internal labour rate assumed by JEN and United Energy was 'relatively high' and 'more consistent with a senior management or executive role, rather than a technical or administrative role'.[42]

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34 AER, *Draft decision*, Appendix L, pp. 157–161.
35 AER, *Draft decision*, p. 158.
36 AER, *Draft decision*, p. 161.
37 CitiPower, *Revised regulatory proposal*, p. 197; Powercor, *Revised regulatory proposal*, p. 187.
38 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 15–17.
39 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 21.
40 SP AusNet, *Revised regulatory proposal*, pp. 249–252.
41 SP AusNet, *Revised regulatory proposal*, pp. 252–253.
42 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 302, 340.

Issues and AER considerations

Process compliance costs

Only JEN and United Energy included opex step changes for the incremental costs associated with preparing and maintaining their ESMSs. The costs proposed for these activities are outlined in table L.3.

Table L.3 Proposed step changes for ESMS process compliance costs ($'000, 2010)

	JEN	United Energy
	992	1725

Note: Includes proposed additional audit costs.
Source: JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 21; United Energy, *Revised regulatory proposal*, p. 89.

ESV reviewed the volume of work proposed by JEN and United Energy to prepare and maintain their ESMSs. ESV advised the AER that it accepted that there would be some additional resources required but considered that the level of resources claimed by JEN and United Energy was excessive in some areas. For example, ESV stated that JEN and United Energy should already have formal incident reporting processes and systems in place.[43]

The AER notes that the proposed work volumes provided by JEN to ESV for review were not consistent with its revised regulatory proposal. JEN and United Energy provided work volumes to ESV that estimated that preparing and maintaining their ESMSs would require 1060 and 1120 man days respectively during the forthcoming regulatory control period. The AER notes that the revised work volumes provided by these DNSPs to ESV reflected JEN's and United Energy's understanding of the regulatory obligations following meetings between the DNSPs and ESV subsequent to the submission of revised regulatory proposals. The AER has considered these volumes, and associated costs, in assessing the step changes proposed by the Victorian DNSPs in their revised regulatory proposals.[44]

Having had regard to the advice provided by ESV, the AER is not satisfied that JEN and United Energy will require all the additional resources proposed to prepare and maintain their ESMSs. The AER notes that ESV advised that they should already have formal incident reporting processes and systems in place and that JEN and United Energy have identified that preparing these would require 350 man days and 360 man days respectively.[45] Consequently, the AER considers that prudent operators in the circumstances of JEN and United Energy would require an additional 710 and 760 man days respectively during the forthcoming regulatory control period to prepare and maintain their ESMS. That is, the man days proposed by JEN and United Energy excluding that required to establish formal incident reporting processes and systems.

[43] ESV, *Assessment by Energy Safe Victorian of EDPR safety-related programs*, 18 October 2010, pp. 6, 14–15.
[44] JEN, Response to information requested 22 September 2010, 30 September 2010; United Energy, Response to information requested 22 September 2010, 28 September 2010.
[45] JEN, Response to information requested 22 September 2010, 30 September 2010; United Energy, Response to information requested 22 September 2010, 28 September 2010.

The AER notes that in estimating the cost of this step change JEN and United Energy assumed an internal cost of $1000 per man day for internal labour and [commercial in confidence].[46] The internal labour rate equates to an annual cost of $210 000 per full time equivalent (FTE) assuming 210 work days per year.[47] Both JEN and United Energy advised the AER that this step change did not include overheads.[48] Consequently, assuming an on-cost multiplier of 1.165 this equates to an annual salary of approximately $180 000.[49]

The AER notes that JEN and United Energy did not provide any justification for the assumption that internal costs would be $1000 per man day. The AER is not satisfied that this reasonably reflects the efficient cost of labour for preparing and maintaining an ESMS.

This view is supported by Nuttall Consulting's assessment of the internal labour rate assumed by JEN and United Energy as 'relatively high' and 'more consistent with a senior management or executive role, rather than a technical or administrative role'. Nuttall Consulting recommended an annual FTE rate of $150 000 per annum.[50] This is consistent with United Energy's assumed labour cost of $150 000 ($2010) per FTE for preparing and maintaining its ESMS in its initial regulatory proposal.[51]

Consequently the AER considers that an internal labour cost of $150 000 ($2010) per FTE, or $714 per man day, reasonably reflects the internal labour cost to JEN and United Energy of preparing and maintaining its ESMS. Consequently the AER considers that JEN and United Energy will require an additional $611 000 ($2010) and $647 000 ($2010) respectively in the forthcoming regulatory control period to prepare and maintain their ESMSs.

Substantive compliance costs

In order to assist its review of the Victorian DNSPs' revised regulatory proposals, the AER sought the assistance of ESV in assessing the Victorian DNSPs' proposed safety related opex and capex proposals. The AER sought to establish whether there was a primary safety driver for the proposed works and, if so, the associated work volumes that must be undertaken in the forthcoming regulatory control period.

Each of the Victorian DNSPs made submissions to ESV to establish the scope and volume of works that they considered to be primarily safety related and that they considered must be undertaken in the forthcoming regulatory control period for the DNSP to comply with its safety obligations.

ESV reviewed the following step changes proposed by JEN:

- neutral condition monitors

46 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 17. United Energy, Response to information requested on 22 September 2010, 28 September 2010.
47 Assuming 11 public holidays, 20 days of annual leave and 20 days of sick leave.
48 JEN, Response to information requested on 11 August 2010, 13 August 2010.
49 On-costs include employer superannuation contributions, payroll tax, worker's compensation premiums and fringe-benefit tax; Victorian Department of Treasury and Finance, *Victorian Guide to Regulation*, 2007, p. C-4.
50 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals,* 22 October 2010, pp. 302, 340.
51 United Energy, *Regulatory proposal*, Appendix B-7, p. 5.

- overhead mounted switchgear inspection and maintenance
- non pole distribution substation routine maintenance
- zone substation transient earth voltage testing
- zone substation pot VT/VT testing
- zone substation transformer dry-outs
- zone substation transformer condition testing.[52]

ESV reviewed the following step changes proposed by SP AusNet:

- increased replacement of conductor ties
- enhanced asset inspection programs.[53]

The AER has assessed these step changes in sections L.5.13, L.5.14, L.5.16.13 and L.5.16.14 of this chapter.

CitiPower, Powercor and United Energy did not submit any of their step changes to ESV for review, other than those relating to line clearance.

AER conclusion

For the reasons discussed above, the AER considers that the step changes outlined in table L.4 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular the efficient expenditure required by a prudent operator to comply with the Electricity Safety Act and the Electricity Safety (Management) Regulations 2009.

Table L.4 AER conclusion on ESMS process compliance cost step change ($'000, 2010)

	JEN	United Energy
	611	647

Note: Includes additional audit costs.
Source: AER analysis.

L.5.1.2 Electricity Safety (Electric Line Clearance) Regulations 2010

AER draft decision

The AER noted that the Electricity Safety (Electric Line Clearance) Regulations 2010 were not made at the time the Victorian DNSPs submitted their initial regulatory proposals. The AER considered that the costs of the proposed Electricity Safety (Electric Line Clearance) Regulations 2010 outlined by ESV in the regulatory impact

52 ESV, *Assessment by Energy Safe Victorian of EDPR safety-related programs*, 18 October 2010, pp. 7–12.
53 ESV, *Assessment by Energy Safe Victorian of EDPR safety-related programs*, 18 October 2010, pp. 23, 25.

statement (RIS) for those regulations resulted in expenditure that reasonably reflected the opex criteria.[54] The cost estimates are outlined in table L.5.

Table L.5 AER draft decision on Electricity Safety (Electric Line Clearance) Regulations 2010 step change ($'m, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
1.2	–17.1	0.9	3.8	1.1

Source: AER, *Draft decision*, Appendix L, p. 171.

The AER also noted that the Victorian DNSPs would have greater certainty over the form of the Electricity Safety (Electric Line Clearance) Regulations 2010 by the time they submitted their revised regulatory proposals. The AER anticipated that the DNSPs would include in their revised regulatory proposals step changes for the impact of these regulations.[55]

Victorian DNSP revised regulatory proposals

CitiPower and Powercor stated in their revised regulatory proposals that the cost impact analysis in the RIS could not be relied upon to determine the cost impact of the new Electricity Safety (Electric Line Clearance) Regulations 2010.[56]

The Victorian DNSPs identified nine changes in the new Electricity Safety (Electric Line Clearance) Regulations relating to:

1. the cessation of exemptions
2. aerial bundled cables and insulated cables (clause 10)
3. powerlines up to 22 kilovolts and 66 kilovolt powerlines in low bushfire risk areas (clause 11)
4. spans exceeding 100 metres (table 2)
5. native trees and trees of cultural or environmental significance (clause 2(3))
6. habitat trees (clause 4)
7. notification and consultation (clause 5)
8. hazard trees (clause 3)
9. overhanging branches (clauses 11(4) and 12(4)).[57]

The total proposed incremental cost impact of these changes is outlined in table L.6.

54 AER, *Draft decision*, Appendix L, p. 170.
55 AER, *Draft decision*, Appendix L, p. 170.
56 CitiPower, *Revised regulatory proposal*, p. 195; Powercor, *Revised regulatory proposal*, p. 185.
57 CitiPower, *Revised regulatory proposal*, pp. 536–561; Powercor, *Revised regulatory proposal*, pp. 543–577; JEN, *Revised regulatory proposal*, Appendix 8.34, confidential; SP AusNet, *Revised regulatory proposal*, pp. 212–214, 239–247; JEN, *Revised regulatory proposal*, Appendix B-5.

Table L.6 Proposed line clearance step change ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
19 194	91 093	11 088	85 781[a]	42 700

a This includes SP AusNet's proposed step change for hazard trees ($20.6m). It does not include SP AusNet's proposed step change for incremental vegetation growth ($8.5m), discussed in section 0, which is not required explicitly by the Electricity Safety (Electric Line Clearance) Regulations 2010.

Source: CitiPower, *Revised regulatory proposal*, p. 211; Powercor, *Revised regulatory proposal*, p. 200; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 51; SP AusNet, Response to information requested 11 August 2010, 18 August 2010; United Energy, *Revised regulatory proposal*, p. 89.

Consultant review

Nuttall Consulting reviewed the unit costs used by the Victorian DNSPs to estimate the incremental cost impact of the Electricity Safety (Electric Line Clearance) Regulations. Generally, Nuttall Consulting found the unit rates proposed by JEN, SP AusNet and United Energy to be efficient. However, Nuttall Consulting considered some of the unit rates proposed by CitiPower and Powercor to not be efficient.[58]

Issues and AER considerations

Subsequent to receiving the Victorian DNSPs' revised regulatory proposals the AER sought additional information from each of the Victorian DNSPs regarding their proposed line clearance step changes. The AER requested that each of the DNSPs provide the AER with the following for each relevant change in the Electricity Safety (Electric Line Clearance) Regulations:

1. a detailed description of the physical change in work practices and other physical requirements relating to each area of change relating to the Electricity Safety (Electric Line Clearance) Regulations
2. identify the proposed step change opex associated with each category for each year of the next regulatory control period
3. identify and describe the individual unit rates and work volumes that have used to develop the step change opex described in (2) above
4. identify and describe any assumptions relied upon in developing the opex step change described in (2) above
5. compare the work volumes and unit costs described in (3) above with actual work volumes and unit costs incurred by the DNSP in the 2009 calendar year and provide evidence supporting any variations from actual unit costs or actual work volumes
6. describe the level of scale efficiencies adopted by the DNSP in forecasting the step change opex described in (2) above. If no scale efficiency was adopted, provide supporting evidence as to why scale efficiencies are not considered applicable.

58 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, Appendix G.

7. provide evidence to support any proposed change to tree trimming or inspection cycles
8. describe and justify the savings that the DNSP anticipates associated with the Electricity Safety (Electric Line Clearance) Regulations 2010
9. quantify the impact that the step changes proposed by the DNPS will have on fault and emergency opex.

The Victorian DNSPs' answers to these questions where used by both the AER and Nuttall Consulting to assess their proposed line clearance step changes, as discussed below.

Cessation of exemptions

Under the Electricity Safety (Electric Line Clearance) Regulations 2005, the Victorian DNSPs were required to maintain the mandated clearance space at all times between vegetation and electric lines. However, the Victorian DNSPs were granted exemptions by ESV that allowed vegetation to enter the clearance space at certain times. While the details of the exemptions varied for each of the DNSPs, broadly:

- the DNSPs were required to achieve and maintain compliance at all times during the fire danger season in hazardous bushfire risk areas (HBRA)
- the DNSPs were required to operate under a plan, approved by ESV, that was designed to achieve and maintain the minimum clearance space requirements in the 2005 line clearance code under normal growth conditions in low bushfire risk areas (LBRA).

The AER notes that these exemptions ceased with the revocation of the regulations and ESV has not granted the DNSPs any exemptions under the Electricity Safety (Electric Line Clearance) Regulations 2010.

All of the Victorian DNSPs stated that the cessation of these exemptions would significantly increase their vegetation management costs.

Table L.7 Proposed step change for the cessation of exemptions ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	UED
450	32 050	4051	29 781	11 573

Source: CitiPower, *Revised regulatory proposal*, p. 554; Powercor, *Revised regulatory proposal*, pp. 556, 570; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 49; SP AusNet, Response to information requested 11 August 2010, 18 August 2010; United Energy, *Revised regulatory proposal*, Appendix B-6.

ESV confirmed to the AER that no such exemptions were applicable under the Electricity Safety (Electric Line Clearance) Regulations 2010, resulting in the requirement for additional or more frequent cutting of vegetation.[59]

[59] ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 3.

ESV reviewed the additional work volumes proposed by the Victorian DNSPs and stated that it considered the proposed number of additional vegetated spans requiring cutting appeared reasonable. However it did question the level of additional resources proposed by JEN and United Energy.[60]

Nuttall Consulting reviewed the unit rates proposed by the Victorian DNSPs. It noted that the unit costs proposed by CitiPower and Powercor were considerably higher than those of the other Victorian DNSPs.[61]

Nuttall Consulting also noted that the information provided by SP AusNet, United Energy and JEN was highly consistent and more detailed than that provided by CitiPower and Powercor. SP AusNet, United Energy and JEN all provided detailed spreadsheets demonstrating how their proposed costs were built up. CitiPower and Powercor, however, did not provide a working spreadsheet or detailed information to the level provided by the other companies.[62]

Nuttall Consulting concluded that it was not possible to determine why the CitiPower and Powercor costs were considerably higher than those of the other Victorian DNSPs. Nuttall Consulting was not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.[63]

Nuttall Consulting considered that the information provided by SP AusNet, United Energy and JEN was sufficient for it to form the view that the unit costs proposed by those DNSPs represented efficient costs for the proposed works. However, it was unable to conclude that the costs proposed by CitiPower and Powercor were efficient and recommended reduced unit rates for CitiPower and Powercor consistent with those proposed by the other DNSPs.[64]

Based on its review of the unit costs assumed by CitiPower and Powercor, the AER agrees with Nuttall Consulting that the costs proposed appear excessive when compared with those proposed by the other DNSPs. The unit rates proposed by each of the DNSPs in HBRAs and LBRAs are detailed in table L.8.

60 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, pp. 4–5, 12–13, 20, 24–25.

61 Nuttall Consulting, *Report—capital expenditure: Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 295, 321–322.

62 Nuttall Consulting, *Report—capital expenditure: Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 296, 321–322.

63 Nuttall Consulting, *Report—capital expenditure: Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 296, 321–322.

64 Nuttall Consulting, *Report—capital expenditure: Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 296, 321–322

Table L.8 Proposed unit rates for vegetation clearance ($ per span, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
LBRA	[c-i-c]	[c-i-c]	[c-i-c]	195	[c-i-c]
HBRA—pre-summer	n.a.	[c-i-c]	[c-i-c]	195	[c-i-c]
HBRA—cyclic	n.a.	[c-i-c]	[c-i-c]	195	[c-i-c]

Source: CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010; JEN, Response to information requested on 11 August 2010, 2 September 2010; SP AusNet, *Revised regulatory proposal*, p. 241; United Energy, Response to information requested on 11 August 2010, 26 August 2010.

However, the AER notes that CitiPower and Powercor did not propose explicit costs for additional line inspections, in contrast to the other DNSPs. The inspection costs proposed by the other DNSPs as a proportion of their proposed pruning costs are outlined in table L.9.

Table L.9 Proposed inspection costs as a percentage of total step change (per cent)

	JEN	SP AusNet	United Energy
	50	35	59

Source: AER analysis.

When inspection costs are taken into account the AER is satisfied that the additional cost proposed by CitiPower and Powercor due to the cessation of the LBRA exemptions reasonably reflect the efficient costs of a prudent DNSP.

However, consideration of inspection costs does not appear to explain why the unit rates proposed by Powercor for cutting in HBRA are significantly higher than those for the other DNSPs. The AER considers that the efficient cost of additional pruning of vegetation in HBRA for Powercor is the rate recommended by Nuttall Consulting ([confidential]for pre-summer cutting and [confidential] for cyclic cutting) inflated by 35 per cent, that is, the equivalent of SP AusNet's proposed inspection costs as a proportion of its pruning costs. The AER considers that the inspection costs of SP AusNet are the most comparable to Powercor since the both operate networks in regional and rural areas.

Further, the AER reviewed the model used by CitiPower's and Powercor's vegetation management contractor to estimate the incremental cost to Powercor of the 2010 line clearance code. The AER notes that the forecast incremental cost in the model is the difference between the forecast cost and the current contract cost, which doesn't cover the changes to the line clearance code. However, the contract cost reduces between 2010 and 2014. Consequently the AER considers that the contractor's estimate of the incremental cost will overstate the step change in costs between those forecast for the forthcoming regulatory control period and the base year (2009).

Having considered the proposed unit rates and CitiPower's and Powercor's vegetation management contractor's HBRA exemption cost model, the AER is not satisfied that the step change proposed by Powercor for the cessation of exemptions in HBRAs is consistent with a total forecast opex that reasonably reflects the opex criteria, and in particular, the efficient costs of a prudent DNSP.

From CitiPower's and Powercor's vegetation management contractor's HBRA exemption model, the AER identified the number of additional spans the contractor will be required to trim due to the cessation of HBRA exemptions, as shown in table L.10.

Table L.10 Additional Powercor spans requiring trimming due to the cessation of HBRA exemptions

	Cyclic	Pre-summer	Easement
2010			
2011		Commercial	
2012		In	
2013			
2014		Confidence	
2015			

Source: Powercor, Response to information requested on 11 August 2010, 31 August 2010.

Given the small number of additional easements the AER considered the proposed expenditure for the clearing of vegetation in easements reasonable. Given the number of additional spans to be cleared and assuming a unit rate of [confidential] for pre-summer cutting and [confidential] for cyclic cutting, the AER has calculated the additional cost of vegetation clearance due to the cessation of HBRA exemption in table L.11.

Table L.11 Incremental cost to Powercor due to the cessation of HBRA exemptions ($'000, 2010)

	Cyclic	Pre-summer	Easement	Total
2011				
2012		Commercial		
2013		In		
2014				
2015		Confidence		
Total				

Source: AER analysis.

For the reasons discussed above, the AER considers that the step changes outlined in table L.12 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflect the efficient costs of a prudent DNSP to comply with the requirements in the 2010 line clearance code.

Table L.12 AER conclusion on step changes for the cessation of exemptions ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	UED
450	21 953	4051	29 781	11 573

Source: AER analysis

Aerial bundled cables and insulated cables

The 2005 line clearance code allowed certain branches and leaves to enter the clearance space of aerial bundled cables under certain circumstances. Specifically:

- small tree branches with a diameter of less than 10 millimetres and leaves could enter the clearance space if, at least once a year, the branches and leaves were removed from the required clearance space[65]
- branches and leaves were not required to be removed from the clearance space annually if the branches and leaves were not likely to abrade the cable before they were next removed in accordance with the code[66]
- existing tree branches exceeding 130 millimetres in diameter could enter the clearance space if the branch was more than 300 millimetres from the cable and a suitably qualified arborist carried out an annual risk assessment on the tree.[67]

These exemptions in the 2005 line clearance code are not included in the 2010 line clearance code.

The Victorian DNSPs stated that the cost impact of this change to the line clearance code is significant because they will have to first establish the required clearances around insulated service lines and aerial bundled cable conductors and then maintain these clearances at all times.[68] The proposed incremental cost impacts of these changes are outlined in table L.13.

65 Clause 9.2.1 of the *Code of practice for electric line clearance* (2005)

66 Clause 9.2.2 of the *Code of practice for electric line clearance* (2005)

67 Clauses 9.3 and 12 of the *Code of practice for electric line clearance* (2005)

68 CitiPower, *Revised regulatory proposal*, p. 549; Powercor, *Revised regulatory proposal*, p. 560. JEN, *Revised regulatory proposal*, Appendix 8.34, confidential. SP AusNet, *Revised regulatory proposal*, pp. 245–247; United Energy, *Revised regulatory proposal*, Appendix B-5.

Table L.13 Proposed step change for aerial bundled cables and insulated cables ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
15 103	35 477	3392	25 831	9919

Source: CitiPower, *Revised regulatory proposal*, p. 548; Powercor, *Revised regulatory proposal*, p. 561; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 49; SP AusNet, response to information requested 11 August 2010, 18 August 2010; United Energy, *Revised regulatory proposal*, Appendix B-6.

ESV confirmed that the exemptions in the 2005 line clearance code that allowed trees to grow into the clearance space of insulated cable under certain condition have been removed from the 2010 line clearance code and that this would result in the need for additional cutting.[69]

ESV reviewed the extra volumes of work proposed by the Victorian DNSPs to maintain the required clearance space around insulated cables and advised the AER that the additional number of spans that the Victorian DNSPs proposed to clear each year appeared reasonable. The volumes reviewed by ESV for JEN and United Energy reflected revised cost estimates compared to those submitted in their revised regulatory proposals.[70]

CitiPower and Powercor were the only DNSPs to propose a step change for the clearance of insulated cables from pole to pole. The other Victorian DNSPs only proposed costs for the clearance of service cables.

Nuttall Consulting reviewed the unit rates proposed by the Victorian DNSPs for clearing vegetation around insulated cables, which are outlined in table L.14.

Table L.14 Proposed unit rates for clearance of insulated cables ($ per span, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Pole to pole	[c-i-c]	[c-i-c]	n.a.	n.a.	n.a.
Service cables—initial cut	[c-i-c]	[c-i-c]	[c-i-c]	83.46	[c-i-c]
Service cables—ongoing	[c-i-c]	[c-i-c]	[c-i-c]	47.40	[c-i-c]

Source: CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010; JEN, Response to information requested on 11 August 2010, 2 September 2010; SP AusNet, *Revised regulatory proposal*, p. 246; United Energy, Response to information requested on 11 August 2010, 26 August 2010.

69 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 2.

70 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, pp. 4–5, 13–14, 20–21, 25.

Nuttall Consulting noted the higher customer density of the CitiPower franchise area and the associated traffic management costs that are inherent with this territory. Despite this Nuttall Consulting considered that the unit rates proposed by CitiPower were excessive in comparison to those proposed by JEN, SP AusNet and United Energy. [71]

Nuttall Consulting noted that the proposed number of spans in CitiPower's network to be cleared did not take into account that insulated spans will often be run on the same poles as other conductors. Nuttall Consulting also noted that the assumed average span length is 25 per cent greater than the actual average span length. Further, both CitiPower and Powercor assumed that there would be neither scale efficiencies nor any associated reduction in fault and emergency opex.[72]

Consequently, having compared the unit rates proposed by all of the Victorian DNSPs, Nuttall Consulting concluded that the unit rates proposed by CitiPower and Powercor for the clearance of insulated cable from pole to pole was not efficient and recommended a unit rate of [confidential].[73]

The AER further notes that unit rates proposed by CitiPower and Powercor do not explicitly take account of the avoided cost of annual arborist risk assessments for tree branches exceeding 130 millimetres as required under the 2005 line clearance code.

Despite this, the AER also notes that the unit rate recommended by Nuttall Consulting is based on the LBRA rate of other Victorian DNSPs. The AER considers that this rate, which is exclusive of inspection costs, is not directly comparable to CitiPower's and Powercor's rate which appears to be inclusive of inspection costs. Consequently, for the same reason supporting the LBRA exemption costs above, the AER is satisfied that the unit rate proposed by CitiPower and Powercor reasonably reflects the efficient cost of maintaining the required clearance around pole to pole insulated cables.

Regarding service cables, Nuttall Consulting considered that the information provided by JEN, SP AusNet and United Energy was sufficient for Nuttall Consulting to form the view that their proposed unit costs were efficient for the proposed works. Nuttall Consulting, however, was unable to conclude that the costs proposed by CitiPower and Powercor were efficient.[74] Nuttall consulting recommended unit rates for CitiPower and Powercor consistent with JEN, SP AusNet and United Energy, taking into account greater consultation and complaints in more highly urban areas, as outlined in table L.15.[75]

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71 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 297–298.

72 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 297–298.

73 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 298, 324.

74 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 299.

75 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 299.

Table L.15 Service line clearance unit rates recommended by Nuttall Consulting ($ per service cable, 2010)

	CitiPower	Powercor
Initial clearance	[c-i-c]	[c-i-c]
Ongoing clearance	[c-i-c]	[c-i-c]

Source: Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals, 22 October 2010*, pp. 299, 325.

The AER assessed the unit rates provided by each of the Victorian DNSPs and agrees with Nuttall Consulting that CitiPower and Powercor did not provide sufficient information to explain why their proposed unit costs for the clearance of insulated cables were significantly greater than those proposed by the other Victorian DNSPs. Consequently the AER is not satisfied that the step changes proposed by those two DNSPs for the clearance of insulated service cables is consistent with a total forecast opex that reasonably reflect the efficient costs of a prudent DNSP to comply with the 2010 line clearance code. The AER considers that the unit rates recommended by Nuttall Consulting reflect the efficient costs of clearing for CitiPower and Powercor.

For the reasons discussed above, the AER considers that the step changes outlined in table L.16 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflect the efficient costs of a prudent DNSP to comply with the requirements in the 2010 line clearance code. The step changes for JEN and United Energy reflect the revised step changes provided to the AER and ESV subsequent to submitting their revised regulatory proposals. The CitiPower and Powercor step changes have been adjusted to reflect the unit rates recommended by Nuttall Consulting.

Table L.16 AER conclusion on aerial bundled cables and insulated cables step change ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
5 316	20 694	3 441	25 831	9 060

Source: AER analysis.

Powerlines up to 22 kilovolts and 66 kilovolt powerlines in low bushfire risk areas

The 2005 line clearance code provided for smaller clearances than would otherwise apply to powerlines of 22 kilovolts or less and powerlines in 66 kilovolts in LBRA if a suitably qualified arborist carried out an annual risk assessment.[76] This allowed mature and slow growing species to be cut to reduced clearances, with an allowance for regrowth.

CitiPower and Powercor stated that this change to the code would increase their vegetation management costs, as outlined in table L.17.

[76] Clauses 10(b)–(c) and 12 of the *Code of practice for electric line clearance* (2005)

Table L.17 Proposed step change for powerlines up to 22 kilovolts and 66 kilovolt powerlines in low bushfire risk areas ($'000, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	990	594	594	594	594	3366
Powercor	2475	2475	1485	1485	1485	9405

Source: CitiPower, *Revised regulatory proposal*, p. 549; Powercor, *Revised regulatory proposal*, p. 562.

ESV confirmed that the exceptions in the 2005 line clearance code that allowed reduced clearance spaces for powerlines of 22 kilovolts or less and powerlines in 66 kilovolts in LBRA under certain conditions were not included in the 2010 line clearance code, resulting in a requirement for additional cutting.[77]

ESV reviewed the extra volumes of work proposed by CitiPower and Powercor to maintain the clearance space around affected powerlines and stated that the number of spans that require a larger clearance space to be established and maintained appeared reasonable.[78]

The AER notes that CitiPower's and Powercor's vegetation management contractor estimated the incremental cost of the removal of this exemption from the 2010 line clearance code for both DNSPs.

CitiPower's and Powercor's vegetation management contractor estimated the number of spans, for both Powercor and CitiPower, that will need to be cut due to the removal of the allowance under the 2005 line clearance code for reduced clearance spaces for powerlines other than ABC or insulated cables in LBRA.[79]

Under clause 12 of the 2005 line clearance code CitiPower and Powercor were required to ensure that a suitably qualified arborist carried out an annual risk assessment for each tree for which they maintained the reduced clearance space. Since the 2010 line clearance code does not provide the Victorian DNSPs the option of trimming vegetation to the reduced clearance spaces, CitiPower and Powercor will no longer need to undertake these annual risk assessments. The AER notes that CitiPower's and Powercor's vegetation management contractor's cost estimates of this step change did not explicitly consider this avoided cost.[80]

Nuttall Consulting reviewed the unit costs proposed by CitiPower and Powercor to maintain the expanded clearance space around those powerlines which previously were cleared to the reduced clearance spaces. Nuttall Consulting noted that the unit rate of [confidential] proposed by CitiPower and Powercor was significantly higher

77 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 3.
78 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, pp. 4–5.
79 CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010
80 CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010

than the unit rate of clearing LBRA lines proposed by the other DNSPs, which varied from $195 ($2010) for SP AusNet to [confidential] for JEN and United Energy.[81]

Further, Nuttall Consulting considered that the information provided by JEN, SP AusNet and United Energy was highly consistent and more detailed than that provided for CitiPower and Powercor. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.[82]

Consequently, Nuttall Consulting stated that it was unable to conclude that the costs proposed by CitiPower and Powercor were efficient. Based on the information provided, Nuttall Consulting considered that the efficient unit rate associated with removal of the 2005 Code exemptions was [confidential], the higher rate of the two proposed by the other DNSPs.[83]

Despite this, the AER notes that the unit rate recommended by Nuttall Consulting is based on the LBRA rate of other Victorian DNSPs. The AER considers that this rate, which is exclusive of inspection costs, is not directly comparable to CitiPower's and Powercor's rate which appears to be inclusive of inspection costs. Consequently, for the same reason supporting the LBRA exemption costs above, the AER is satisfied that the unit rate proposed by CitiPower and Powercor reasonably reflects the efficient cost of clearing previously exempt 22 kilovolt and 66 kilovolt powerlines in LBRA.

For the reasons discussed above the AER is satisfied that the step changes proposed by CitiPower and Powercor for the management of powerlines up to 22 kilovolts and 66 kilovolt powerlines in low bushfire risk areas in accordance with the 2010 line clearance code is consistent with a total forecast opex that reasonably reflect the efficient cost of a prudent DNSP.

Accordingly, the AER considers that $3.4 million ($2010) and $9.4 million ($2010) as proposed by CitiPower and Powercor respectively is part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflects the efficient costs of a prudent DNSP to comply with the requirements in the 2010 line clearance code.

Spans exceeding 100 metres

The 2010 line clearance code requires a larger clearance space for spans exceeding 100 metres in LBRA than was required by the 2005 line clearance code.[84]

Powercor stated that this increased clearance space for spans greater than 100 metres in LBRA would increase their vegetation management costs by $1.46 million each year or $7.3 million over the forthcoming regulatory control period.[85]

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81 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 295.
82 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 296.
83 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 296, 326.
84 Table 2 of the 2010 line clearance code; Table 10.1 of the 2005 line clearance code.
85 Powercor, *Revised regulatory proposal*, p. 563.

Powercor's vegetation management contractor estimated the incremental cost for Powercor. The contractor assumed that most of the vegetated spans in LBRA exceeding 100 metres would require an extra cut over the forthcoming regulatory control period.[86]

ESV confirmed that the 2010 line clearance code requires larger clearances in LBRA for spans in excess of 100 metres, resulting in a requirement for additional cutting.[87]

ESV reviewed the extra volume of work proposed by Powercor and advised the AER that the number of additional spans that would require the establishment of a wider clearance space appeared reasonable.[88]

The AER notes that Powercor's vegetation management contractor estimated a unit rate of [confidential] for the clearance of 100 metre spans is higher than other LBRA average unit rates proposed by other DNSPs. The contractor stated that this higher rate is due to the proximity of these spans to irrigated areas and that there will be more vegetation per span. The contractor stated that the unit rates for cutting in HBRA provide a better guide to the cost per span of the incremental work activities required on Powercor's spans exceeding 100 metres in LBRA.[89]

While Nuttall Consulting considered that spans on irrigated land and land adjacent to irrigation channels were likely to have less vegetation requiring trimming than the average span in LBRA, it agreed that the 'unit rates for cutting in HBRA provide a better guide to the cost per span of the incremental work activities required on Powercor's spans exceeding 100 metres'.[90]

However, as for the cyclic clearing of HBRA, Nuttall Consulting considered that the unit rate estimated was not efficient and recommended that the average cost per span of [confidential] was appropriate for the clearing of spans in excess of 100m in LBRAs.[91] This rate was consistent with the rate proposed by other Victorian DNSPs for the clearance of HBRA spans.

The AER agrees with Nuttall Consulting that in comparison to the unit rates proposed by the other DNSPs for trimming spans in HBRA the rates proposed by Powercor appear excessive. However, as discussed above in relation to HBRA exemption costs, the AER considers that Powercor's proposed unit rate is not directly comparable to the rate proposed by JEN and United Energy of [confidential]since the Powercor rate is inclusive of inspection costs while the JEN and United Energy rate is exclusive. Consequently the AER considers that [confidential] reasonably reflects the efficient unit rate of clearing spans exceeding 100 metres in LBRAs for a prudent DNSP. That

86 Powercor, Response to information requested on 11 August 2010, 31 August 2010.

87 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 3.

88 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 6.

89 Powercor, Response to information requested on 11 August 2010, 31 August 2010.

90 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 327; Powercor, Response to information requested on 11 August 2010, 31 August 2010.

91 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 328.

is, the rate proposed by JEN and United Energy inflated by 35 per cent to incorporate inspection costs.

For the reasons discussed above, the AER considers the step change outlined in table L.18 is part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflects the efficient costs of a prudent DNSP to comply with the requirements in the 2010 line clearance code.

Table L.18 AER conclusion on step change for powerlines exceeding 100 metres in low bushfire risk areas ($'000, 2010)

	2011	2012	2013	2014	2015	Total
Powercor	776	776	776	776	776	3881

Source: AER analysis.

Native trees and trees of cultural or environmental significance

Under the 2010 line clearance code DNSPs are required, as far as practicable, to 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.[92]

CitiPower and Powercor stated that this requirement would significantly increase their vegetation management costs, as outlined in table L.19, because a large proportion of the vegetation cleared in their networks would be classified as 'native'.

Table L.19 Proposed step change for native trees and trees of cultural or environmental significance ($'000, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	–	18	46	92	123	280
Powercor	–	764	1019	2038	2547	6368

Source: CitiPower, *Revised regulatory proposal*, p. 551; Powercor, *Revised regulatory proposal*, p. 565.

ESV advised the AER that the reference to 'native' trees is new but that the requirements for the management of native trees were not. ESV stated that the 2010 line clearance code:

> … consolidates and restates the implicit obligation under the previous regulation as well as the existing obligations under the Planning and Environment Act and the conditions attached to DSE's exemption from permit requirements if minimising cutting and complying with the Code. Clause 2(3) does not empower the removal of mature trees if the Code requirements can be met by pruning, and to that extent the clause could lead to additional cutting.[93]

CitiPower's and Powercor's vegetation management contractor estimated the incremental cost for CitiPower and Powercor. The contractor considered that this

92 Clause 2(3) of the *Code of practice for electric line clearance.*

93 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 2.

regulatory requirement would restrict the DNSPs' ability to remove well grown and mature native trees.[94] The contractor noted that:

> [Commercial
>
> in
>
> Confidence][95]

CitiPower's and Powercor's vegetation management contractor assumed that by restricting the removal of well grown and mature trees the unit cost to clear lines will increase due to an increase in the density of work required per span as native vegetation grows over the period and more native vegetation per span is required to be trimmed.[96]

CitiPower's and Powercor's vegetation management contractor also assumed that the number of spans that it will be required to clear will also increase for both CitiPower and Powercor due to the restrictions on cutting and removing native trees.[97]

ESV reviewed the volume of additional work proposed by CitiPower and Powercor and stated that the proposed number of additional spans required to be cleared appeared reasonable.[98]

The AER notes that CitiPower's and Powercor's vegetation management contractor did not provide the basis for its estimates for the increase in spans that will be required to be cleared. However, the AER notes that the contractor did state that it took the avoided cost of the removal of vegetation into account:

> [Commercial
>
> in
>
> Confidence] [99]

However, the AER notes that CitiPower's and Powercor's vegetation management contractor implicitly assumed that the annual cost of trimming a tree is similar to the cost of removing that same tree. This is made evident when the contractor states that:

> [Commercial in confidence]

94 CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010.
95 CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010.
96 CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010.
97 CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010.
98 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, pp. 4–6.
99 CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010.

[Commercial in confidence]

[Commercial in confidence][100]

The AER considers that the cost of removing a tree is greater than the cost of trimming a tree. For example, the unit cost proposed by JEN and United Energy for the removal of a hazard tree is six times greater than the cost of cutting a hazard tree.[101]

If the avoided cost of removing a mature native tree is six times the annual cost of trimming that tree then the avoided cost of tree removal during the 2011–15 regulatory control period will be approximately two times greater than the additional tree trimming costs.[102] That is, by trimming mature native trees rather than removing them, costs will be reduced during the forthcoming regulatory control period. Further, for the avoided cost of removing native trees to be less than the associated trimming costs then the cost of removing a tree must be less than three times the annual cost of trimming that tree.[103]

It should be noted that this analysis does not suggest that CitiPower's and Powercor's current practice of removing certain mature trees is inefficient because this analysis has not considered the perpetual annual trimming costs beyond the forthcoming regulatory control period.

Consequently the AER is not satisfied that CitiPower's and Powercor's vegetation management contractor has appropriately considered the avoided cost of tree removal in their cost estimate of the impact of the native tree requirements in the 2010 line clearance code. Further, the AER is not satisfied that the additional tree trimming costs associated with the new native tree requirements in the 2010 line clearance code will be greater than the avoided cost of removing mature native trees.

Similarly, Nuttall Consulting noted that the CitiPower's and Powercor's vegetation management contractor's information relating to native trees or trees of cultural or environmental significance did not identify a cost reduction associated with the halt on the removal of this vegetation.[104]

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[100] CitiPower and Powercor, Response to information requested on 11 August 2010, 31 August 2010.

[101] JEN, Response to information requested on 11 August 2010, 2 September 2010, United Energy, Response to information requested on 11 August 2010, 26 August 2010.

[102] Assume that a DNSP would otherwise have removed one native tree per year at a cost of six dollars per tree. Tree removal would cost $30. Assuming that not removing a tree increases annual tree trimming costs by one dollar from that year, then the additional tree trimming costs are $15 (one dollar in 2011, two dollars in 2012, three dollars in 2013 and so forth). Consequently, removal costs would be twice that of trimming costs.

[103] Similar to the footnote above, if tree trimming costs one dollar per tree additional tree trimming costs will be $15 if one less tree per year is removed. If tree removal costs are three dollars per tree then removing one tree per year would also cost $15. Consequently, if the cost of tree removal is less than three times the annual trimming cost then tree trimming costs during the forthcoming regulatory control period will be greater than the avoided cost of tree removal.

[104] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 300, 329.

The AER notes that Nuttall Consulting was not provided sufficient information on the basis for CitiPower's and Powercor's vegetation management contractor's proposed unit rate for the trimming of native trees and stated that it was not possible for Nuttall Consulting to comment on whether the unit rate proposed was efficient or not.[105]

For the reasons discussed above the AER is not satisfied that the step changes proposed by CitiPower and Powercor for the management of native trees and trees of cultural or environmental significance in accordance with the 2010 line clearance code is consistent with a forecast total opex that reasonably reflect the efficient cost of a prudent DNSP.

Habitat trees

Under the 2010 line clearance code, if a tree is the habitat for threatened fauna DNSPs must, wherever practicable, only cut or remove that tree outside of the breeding season for that species. If it is not practicable to cut or remove the tree outside of the breeding season, the animal must be translocated wherever practicable.[106]

All of the Victorian DNSPs, except CitiPower, stated that this new requirement would increase their vegetation management costs, as shown in table L.20.

Table L.20 Proposed step change for habitat trees ($'000, 2010)

Powercor	JEN	SP AusNet	United Energy
500	1165	9584	2225

Source: Powercor, *Revised regulatory proposal*, p. 566; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 50; SP AusNet, response to information requested 11 August 2010, 18 August 2010; United Energy, *Revised regulatory proposal*, Appendix B-6.

Subsequent to the DNSPs submitting their revised proposals, ESV advised JEN and United Energy that clause 4 of the 2010 line clearance code:

> … does not require Major Electricity Companies (MECs) to themselves identify the location of 'habitat' trees—MECs can continue the current practice of obtaining information from local councils, government departments and community groups who hold such information. ESV considers that an MEC will have met its obligation in regard to identifying the location of 'habitat' trees if it accesses the information held by others. On this basis, ESV does not see the need for MECs to require the services of specialist resources to identify 'habitat' trees.[107]

Consequently both JEN and United Energy revised their cost estimates for the management of habitat trees under the 2010 line clearance code to $312 000 ($2010).[108]

105 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 300, 329.

106 Clause 4 of the *Code of practice for electric line clearance.*

107 ESV, Letter to Mr Greg Williams, 20 August 2010.

108 JEN, Response to information requested on 11 August 2010, 2 September 2010; United Energy, Response to information requested on 11 August 2010, 26 August 2010.

ESV reviewed the extra volume of work proposed by JEN, SP AusNet and United Energy for the management of habitat trees and advised the AER that it considered that the new habitat trees requirements in the 2010 line clearance code would require additional record management and administration resources. Consequently, ESV advised the AER that the work volumes estimated by JEN and United Energy appeared reasonable.[109]

Regarding SP AusNet's habitat tree management proposal, ESV stated:

> SP AusNet has claimed an additional 22 FTEs, on the assumption that it has the responsibility to make the assessment in regard to endangered fauna. ESV considers that the distributors do not have to make the assessment themselves, but can rely on registers held by others. On this basis, ESV considers that the additional resource required would be 3 FTEs (one for each of SP AusNet's regions).[110]

Based on the advice provided by ESV that the DNSPs do not require the services of specialist resources to identify habitat trees, the AER is not satisfied that the opex proposed by SP AusNet for the management of habitat trees is consistent with a total forecast opex that reasonably reflects the efficient costs that a prudent DNSP would require to comply with it obligations under the 2010 line clearance code.

The AER considered the unit rates assumed by each of the Victorian DNSPs for the additional staff to manage habitat trees, which are outlined in table L.21 and notes that the rates for the additional staff varied across the DNSPs.

Table L.21 Proposed cost, per FTE, of managing habitat trees ($'000, 2010)

JEN	Powercor	SP AusNet	United Energy
[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]

Source: JEN, Response to information requested on 11 August 2010, 2 September 2010; Powercor, Response to information requested on 11 August 2010, 31 August 2010; SP AusNet, Response to information requested on 11 August 2010, 18 August 2010, p. 246; United Energy, Response to information requested on 11 August 2010, 26 August 2010.

Nuttall Consulting reviewed the unit rates proposed by each of the DNSPs, except Powercor. It noted that the salary assumed by JEN and United Energy was for a scientific/environmental specialist role within its salary band structure. Nuttall Consulting considered the unit rate assumed to be reasonable for the proposed role.[111]

Nuttall Consulting noted that for SP AusNet the role of the three FTEs described by ESV would largely be an administrative one. That is, the staff would be required to collate information on the habitats of endangered species held on registers managed by other organisations. On that basis, Nuttall Consulting recommended the

109 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, pp. 2, 14, 32.

110 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 25.

111 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 319, 358.

SP AusNet's administrative unit rate of [confidential] was appropriate for the role.[112]

The AER notes that the unit rate proposed by SP AusNet included the use of a vehicle. However, based on the advice of ESV, the AER considers that the work to be undertaken would largely be of an administrative nature and a vehicle would not be required. Consequently the AER is not satisfied that the unit rate assumed by SP AusNet is efficient. Since the work to be undertaken is largely administrative the AER considers that SP AusNet requires two FTE undertaking administrative duties at the rate recommended by Nuttall Consulting ([confidential]) and one FTE for a scientific/environmental specialist role at the rate proposed by JEN and United Energy ([confidential]). This equates to an average FTE rate of [confidential].

ESV did not review Powercor's proposed step change for the management of habitat trees under the 2010 line clearance code. However, based on the advice from ESV regarding the other DNSPs, the AER is satisfied that the volume of work proposed by Powercor reasonably reflects the efficient volume of work required by a prudent DNSP to comply with the habitat tree requirements in the 2010 line clearance code. Further, by comparison to the unit rates proposed by the other DNSP, the AER is satisfied that the unit rate assumed by Powercor reasonably reflect the efficient costs of a prudent DNSP.

For the reasons discussed above, the AER considers that the step changes outlined in table L.22 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflect the efficient costs of a prudent DNSP to comply with the habitat tree requirements in the 2010 line clearance code.

Table L.22 AER conclusion on habitat trees step change ($'000, 2010)

Powercor	JEN	SP AusNet	United Energy
500	312	1200	312

Source: AER analysis.

Notification and consultation

Under the 2010 line clearance code, DNSPs are required to notify all affected persons of any intentions to cut or remove a tree that is within the boundary of a private property or is of cultural or environmental significance. The code states that the notice may be given in writing or by publication in a newspaper. Further, if the tree is within the boundary of a private property the DNSP must consult with the occupier of the land if the tree is to be cut, or the owner of the land if the tree is to be removed.[113]

The AER notes that the Victorian DNSPs' estimates of the impact of the notification and consultation requirements in the 2010 line clearance code were significantly different, as outlined in table L.23.

112 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals,* 22 October 2010, p. 335.

113 Clause 5 of the *Code of practice for electric line clearance.*

Table L.23 Proposed step change for notification and consultation ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
–5	–8	1823	–	12 216

Source: CitiPower, *Revised regulatory proposal*, p. 550; Powercor, *Revised regulatory proposal*, p. 564; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 48; SP AusNet, *Revised regulatory proposal*; United Energy, *Revised regulatory proposal*, Appendix B-6.

ESV advised the AER that, in regard to notification and consultation, it 'considers that the changes to the regulations represent a small reduction in burden on the electricity distributors'.[114] Further, the ESV stated that it did not support the additional expenditure for notification and consultation proposed by JEN and United Energy.[115]

Consequently the AER is not satisfied that the step changes proposed by JEN and United Energy are consistent with a total forecast opex that reasonably reflects the efficient costs of a prudent DNSP to comply with the notification and consultation requirements in the 2010 line clearance code.

The AER reviewed the step changes proposed by CitiPower and Powercor and is satisfied that they are consistent with a total forecast opex that reasonably reflects the efficient costs of a prudent DNSP to comply with the notification and consultation requirements in the 2010 line clearance code.

SP AusNet did not propose a reduction in its notification and consultation costs. This is not consistent with the advice of ESV, which stated the regulatory change represented a small reduction in burden. However, because the reduction in burden is only small, the AER considers that SP AusNet's proposed zero step change reasonably reflects the efficient costs.

For the reasons discussed above, the AER considers that the step changes outlined in table L.24 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflect the efficient costs of a prudent DNSP to comply with the notification and consultation requirements in the 2010 line clearance code.

Table L.24 AER conclusion on notification and consultation step change ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
–5	–8	–	–	–

Source: AER analysis.

Hazard trees

The 2010 line clearance code allows for trees that have been identified as being likely to fall onto an electric line to be cut or removed provided that the tree has been

114 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 2.

115 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, pp. 13, 20.

assessed by a suitably qualified arborist.[116] No such provision was included in the 2005 line clearance code.

In the draft decision, the AER considered that SP AusNet had not demonstrated that the hazard trees step change included in its initial regulatory proposal was linked to a new or changed regulatory obligation or requirement. Further, the AER noted that SP AusNet stated that its proposal went beyond line clearance requirements prescribed in Victorian legislation.[117]

The AER recognised the importance of bushfire mitigation but considered that it would not be prudent to approve the proposed hazard trees step change until the Victorian Bushfires Royal Commission's recommendations, and the Victorian Government's response to those recommendations, were released.[118]

JEN, SP AusNet and United Energy all included an opex step change for the management of hazard trees in their revised regulatory proposals, as outlined in table L.25.

Table L.25 Proposed step change for hazard trees ($'000, 2010)

JEN	SP AusNet	United Energy
658.2	20 585.5	2187.5

Source: JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 51; SP AusNet, response to information requested 11 August 2010, 18 August 2010; United Energy, *Revised regulatory proposal*, Appendix B-6.

ESV advised the AER that:

> Although the 2010 Code does not mandate the cutting or removal of hazard trees, ESV supports their cutting or removal as required to mitigate the risk of fire ignitions.[119]

The AER notes that the Victorian Bushfires Royal Commission (VBRC) made two recommendations relating to the management of hazard trees. Recommendation 30 recommended that:

> The State amend the regulatory framework for electricity safety to require that distribution businesses adopt, as part of their management plans, measures to reduce the risks posed by hazard trees—that is, trees that are outside the clearance zone but that could come into contact with an electric power line having regard to foreseeable local conditions.[120]

Recommendation 31 recommended that:

> Municipal councils include in their municipal fire prevention plans for areas of high bushfire risk provision for the identification of hazard trees and for

116 Clause 3 of the *Code of practice for electric line clearance*.
117 AER, *Draft decision*, Appendix L, p. 183.
118 AER, *Draft decision*, Appendix L, p. 184.
119 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 3.
120 Victorian Bushfires Royal Commission, Final report, Volume 2, p. 167.

notifying the responsible entities with a view to having the situation redressed.[121]

The Victorian Government supported both of these recommendations.[122]

On 15 September 2010 the *Energy and Resources Legislation Amendment Act 2010* was granted royal assent. This act will amend the *Electricity Safety Act 1998* to introduce the requirement that municipal councils specify in their municipal fire prevention plans:

(a) procedures and criteria for the identification of trees that are likely to fall onto, or come into contact with, an electric line (hazard trees); and

(b) procedures for the notification of responsible persons of trees that are hazard trees in relation to electric lines for which they are responsible.[123]

The AER notes that the 2010 line clearance code allows DNSPs to remove hazard trees outside the clearance space but does not require them to do so. However, the general duty in the Electricity Safety Act requires the DNSPs to minimise hazards and risks as far as practicable.[124] Consequently, the AER considers that the Victorian DNSPs are required to remove or cut, as necessary, any hazard trees that it, or any other party, identifies.

However, the AER also notes that the amendments to the Electricity Safety Act require municipal councils, not DNSPs, to identify hazard trees. Consequently the AER considers that the Victorian DNSPs are not required to actively search for, and identify, hazard trees. The Victorian DNSPs must, however, appropriately manage hazard trees that they identify in the normal operation and maintenance of their networks or which are identified by municipal councils or any other party.

The AER sought further information from the Victorian DNSPs on how they estimated the incremental cost of the new regulations. In response, JEN and United Energy advised the AER that they had revised their estimates of the cost impact of hazard trees and that the cost impact would be $0.68 million ($2010) and $1.43 million ($2010) respectively.

ESV reviewed the number of hazard trees proposed to be removed or trimmed by JEN, SP AusNet and United Energy and advised the AER that it considered the volumes proposed appeared reasonable.[125]

Nuttall Consulting assessed the tree removal costs proposed by JEN, SP AusNet and United Energy, as outlined in table L.26, against those advised by the Australian

121 Victorian Bushfires Royal Commission, Final report, Volume 2, p. 167.

122 Victorian Government, *Victorian Government response to recommendations of the Victorian Bushfire Royal Commission final report*, 27 August 2010, p. 16.

123 Section 86B of the Electricity Safety Act as amended by the Energy and Resources Legislation Amendment Act. This amendment is to commence on or before 1 July 2011.

124 Section 98 of the Electricity Safety Act.

125 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, pp. 14, 21, 24.

Institute of Architects (AIA). This cost guide suggested tree removal costs in Melbourne of between $300 and $1600 per tree.[126]

Table L.26 Unit cost of removing/cutting hazard trees ($, 2010)

	JEN	SP AusNet	United Energy
Tree removal	[c-i-c]	Not provided	[c-i-c]
Tree cutting	[c-i-c]	Not provided	[c-i-c]
Average cost per tree	[c-i-c]	823	[c-i-c]

Source: JEN, Response to information requested on 11 August 2010, 2 September 2010; SP AusNet, Response to information requested 11 August 2010, 18 August 2010; United Energy, Response to information requested on 11 August 2010, 26 August 2010.

Nuttall Consulting noted that the trees likely to be considered a hazard will tend towards larger and older trees that are taller than the overhead lines. On this basis, Nuttall Consulting considered the unit rate for the removal of a hazard trees proposed by JEN and United Energy to be reasonable.[127]

Nuttall Consulting also noted that the unit rate for trimming of a hazard tree proposed by JEN and United Energy exceeds the cyclic span clearing rates proposed by those businesses. Because a typical span will have more than one tree encroaching the clearance space this suggests an even lower per tree trimming cost. However, hazard trees will often not have ready street access and will require trimming at a greater height than is typical for cyclic trimming. Consequently, on balance, Nuttall Consulting considered that the trimming cost of a hazard tree proposed by JEN and United Energy was reasonable.[128]

Nuttall Consulting noted that the per tree costs proposed by SP AusNet was between the tree removal and trimming costs proposed by JEN and United Energy and may represent a reasonable assessment of the average cost of both trimming and removal. However, Nuttall Consulting stated that without a more detailed breakdown of the activity types SP AusNet was proposing to undertake, it was unable to determine a more accurate assessment of the relative efficiencies of these activities.[129]

The AER notes that the average cost per hazard tree proposed by SP AusNet was greater than that proposed by both JEN and United Energy. SP AusNet did not include in its initial or revised regulatory proposals the assumed cost for removing and trimming of hazard trees or the assumed split between these two different activities. The AER notes that SP AusNet is proposing to manage a significantly greater number of hazard trees each year. Consequently the AER considers that this should deliver

[126] The Royal Australian Institute of Architects, *Archicentre cost guide*, January 2008, p. 3.
[127] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 319, 359.
[128] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 319, 359.
[129] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 333.

some economies of scale. However, the AER also notes that since SP AusNet's network covers rural and remote areas it will likely incur greater travel costs.

Despite this, and considering that the average rate per tree proposed by SP AusNet is between the hazard tree removal and trimming costs proposed by JEN and United Energy, the AER is satisfied that SP AusNet's proposed hazard tree program reasonably reflects the efficient cost of addressing hazard trees.

For the reasons discussed above, the AER considers that the step changes outlined in table L.27 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflect the efficient costs of a prudent DNSP to comply with the hazard tree requirements in the 2010 line clearance code.

Table L.27 AER conclusion on hazard trees step change ($'000, 2010)

	JEN	SP AusNet	United Energy
	680	20 586	1425

Source: AER analysis.

Overhanging branches

The 2005 line clearance code allowed branches to overhang powerlines in HBRA and 66 kV powerlines in LBRA if an annual risk assessment was undertaken by a suitably qualified arborist.[130] These exemptions have been removed from the 2010 line clearance code such that branches overhanging powerlines in HBRA and 66kV powerlines in LBRA must now be removed.

United Energy stated that the removal of these exemptions from the 2010 line clearance code will increase its vegetation management opex by $4.6 million ($2010) during the forthcoming regulatory control period. United Energy stated that the removal of overhanging branches is not feasible in some locations requiring those spans to be placed underground or replaced with aerial bundled cable (over which branches are allowed to hang).[131] This proposed capital expenditure is considered in appendix P.

ESV advised the AER that the removal of these exceptions 'will result in additional pruning, tree removal and engineering solutions to remove the overhangs'.[132]

ESV reviewed the volume of work proposed by United Energy to remove overhanging branches and advised the AER that the number of spans that will require annual removal of overhanging branches appeared reasonable.[133]

Nuttall Consulting reviewed the unit costs proposed by United Energy and considered that United Energy had not provided sufficient information to determine if the

130 Clauses 10(c), 11.2 and 12 of the 2005 line clearance code. Note that the 2005 line clearance code allowed branches to overhang powerlines up 22kV in LBRA without an arborist risk assessment.
131 United Energy, *Revised regulatory proposal*, Appendix B-5, pp 3–4.
132 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 3.
133 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 21.

proposed unit rate of [confidential] per span was reasonable and reflected an efficient cost. Nuttall Consulting recommended a unit rate of [confidential] per span.[134]

Despite the concerns raised by Nuttall Consulting, the AER notes that the unit rate of [confidential] per span proposed by United Energy for the clearance of overhanging branches equates to the cutting of [c-i-c] hazard trees. The AER considers that the clearance of overhanging branches will cost more than the clearance of a regular span in LBRA. By comparison to the unit rate for cutting a hazard tree, and considering that a span will have a number of overhanging branches, the AER is satisfied that the proposed unit rate reasonably reflects the cost of clearing overhanging branches in LBRA.

For the reasons discussed above, the AER considers $4.6 million ($2010) as proposed by United Energy is part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflects the efficient costs of a prudent DNSP to comply with the 2010 line clearance code.

AER conclusion

For the reasons discussed above, the AER considers that the step changes outlined in table L.28 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflects the efficient expenditure required by a prudent operator to comply with the 2010 line clearance code.

The AER's conclusion on line clearance step changes for CitiPower and Powercor reflects the AER's consideration that their proposed unit rates for the clearance of electric lines in HBRA was not efficient and that the unit rate for the clearance of native trees did not appropriately consider the avoided cost of removing mature trees.

For JEN and United Energy, as discussed above, the AER considers that the step changes proposed for notification and consultation are not consistent with the ESV's advice that the changes to the regulations represent a small reduction in burden on the electricity distributors.

The AER also considered that SP AusNet's proposed step change for the management of habitat trees was not consistent with the ESV's advice that the changes to the regulations do not require the Victorian DNSPs to themselves identify the location of habitat trees.

Table L.28 AER conclusion on line clearance step changes ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
9127	56 425	9016	77 398[a]	29 914

a This includes SP AusNet's proposed step change for hazard trees. It does not include SP AusNet's proposed step change for incremental vegetation growth which is discussed in section 0.

Source: AER analysis.

[134] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 361.

L.5.1.3 Electricity Safety (Bushfire Mitigation) Regulations 2003

AER draft decision

The AER noted that under the Electricity Safety (Bushfire Mitigation) Regulations 2003, the Victorian DNSPs are required to inspect private overhead electric lines (POELs):

- no later than 37 months after the date of the previous inspection, or
- at other times, not exceeding 5 years from the date of the previous inspection, approved by ESV.[135]

Further, ESV had advised JEN, SP AusNet and United Energy that they must either provide a detailed risk assessment for maintaining their current inspection cycles for POELs or adopt a three year inspection cycle.[136]

The AER determined that a step change should be provided to JEN, SP AusNet and United Energy to increase the frequency of their POEL inspection cycle, as outlined in table L.29.

Table L.29 AER draft decision on increased POEL inspection frequency step change ($'000, 2010)

	JEN	SP AusNet	United Energy
	32	1522	328

Source: AER, *Draft decision*, Appendix L, p. 173.

Victorian DNSP revised regulatory proposals

JEN proposed a step change for the inspection of POELs consistent with the AER's draft decision, with real cost escalation applied to the step change.[137]

SP AusNet stated that it agreed with the AER's draft decision, subject to updating the step change for labour cost escalation.[138]

United Energy proposed a step change of $272 000 ($2010) to increase the frequency of POEL inspection, consistent with its initial regulatory proposal. United Energy stated that the AER had rejected its initial proposal but that it was prudent to increase the frequency of POEL inspection, and that it should be provided with operating expenditure to enable it to do so.[139]

135 Regulation 7 of the Electricity Safety (Bushfire Mitigation) Regulations 2003.
136 JEN, *Regulatory proposal*, Appendix 10, confidential, 30 November 2009, p. 54; SP AusNet, *Regulatory proposal*, p. 219; United Energy, *Regulatory proposal*, p. 59.
137 JEN, *Revised regulatory proposal, Appendix 7.2*, confidential, p. 8.
138 SP AusNet, *Revised regulatory proposal*, p. 234.
139 United Energy, *Revised regulatory proposal*, p. 91.

Table L.30 Victorian DNSP revised proposed step change for increased POEL inspection frequency ($'000, 2010)

	JEN	SP AusNet	United Energy
	32	1902	272

Source: JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 8; SP AusNet Response to information requested on 11 August 2010, 18 August 2010; United Energy, *Revised regulatory proposal*, p. 91.

Issues and AER considerations

The AER's has considered the application of real cost escalators to opex step changes in appendix K. The AER considers that, consistent with its treatment of base year costs, real cost escalation should be applied to opex step changes.

Despite stating that it agreed with the AER draft decision SP AusNet's proposed step change for the inspection of POELs in its revised proposal was greater than that determined by the AER in its draft decision.[140] SP AusNet's revised proposal for the inspection of POELs appears to be consistent with its initial proposal, not the AER's draft decision. The AER's draft decision was based upon a more granular cost estimate provided by SP AusNet to the AER subsequent to submitting its initial regulatory proposal. Given that SP AusNet stated that the estimate upon which the AER based its draft decision was a more granular estimate, and that it agreed with the AER's draft decision, the AER is not satisfied that SP AusNet's proposed POEL step change reasonably reflects the efficient costs that a prudent DNSP would require to comply with the Electricity Safety (Bushfire Mitigation) Regulations 2003. The AER considers that its draft decision remains the best estimate of the costs to SP AusNet of complying with the Electricity Safety (Bushfire Mitigation) Regulations.

The AER notes that in its draft decision it determined a step change for United Energy for an increase in frequency of POEL inspection greater than that proposed by United Energy in its initial regulatory proposal. Subsequent to submitting its initial regulatory proposal, United Energy advised the AER that it had a made an error in its estimate of the cost impact and revised its estimate upward. The AER used this revised cost estimate to determine the expenditure required for POEL inspections that reasonably reflects the opex criteria, including the opex objectives. The step change determined for United Energy for POEL inspection costs in the draft decision was greater that that proposed by United Energy in both its initial and revised regulatory proposals.[141]

The AER sought advice from United Energy regarding its POEL inspection step change since United Energy had stated that the AER had rejected a step change for POEL inspections in the draft decision when this was not the case. United Energy stated that it agreed with the POEL inspection step change in the AER's draft decision.[142]

[140] SP AusNet, *Revised regulatory proposal*, p. 234; AER, *Draft decision*, Appendix L, p. 173.
[141] AER, *Draft decision*, Appendix L, pp. 172–173.
[142] United Energy, Response to information request on 19 August 2010, 25 August 2010.

AER conclusion

For the reasons discussed above, the AER considers that the step changes outlined in table L.31 are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflect the efficient costs of a prudent operator complying with the Electricity Safety (Bushfire Mitigation) Regulations.

Table L.31 AER conclusion on increased POEL inspection frequency step change ($'000, 2010)

	JEN	SP AusNet	United Energy
	32	1522	328

Source: AER analysis

L.5.1.4 Increase in annual levy paid to Energy Safe Victoria

AER draft decision

The AER did not review this proposal in the draft decision because it was not raised in the Victorian DNSPs' initial regulatory proposals.

Victorian DNSP revised regulatory proposals

The increase in the annual levy to be paid to ESV by the Victorian DNSPs during the 2011–15 regulatory control period was not raised in the Victorian DNSPs' revised regulatory proposals because the Victorian DNSPs were informed of the increase by the ESV in October 2010.

Following this, the Victorian DNSPs raised the matter with the AER and each proposed a step change to meet the new obligation.[143]

Issues and AER considerations

Payment of a levy to the ESV is a regulatory obligation of the Victorian DNSPs.

The AER has verified with the ESV the level of increase in the levy to be paid to ESV by the Victorian DNSPs during the 2011–15 regulatory control period.[144] The increase for each Victorian DNSP is set out in the table below.

The AER considers that these step changes reasonably reflect the opex criteria as the increases set out below reflect the additional costs to be incurred by the Victorian DNSPs during the 2011–15 regulatory control period for the ESV levy.

AER conclusion

The AER considers that the step changes below are part of a total forecast opex that reasonably reflects the opex criteria, and in particular reflect the efficient costs of a prudent DNSP to comply with the applicable regulatory obligations regarding the ESV levy for Victorian DNSPs.

143 United Energy wrote to the AER on 14 October 2010. SP AusNet, CitiPower and Powercor wrote to the AER on 18 October 2010. JEN wrote to the AER on 19 October 2010.

144 ESV, Email from Paul Fearon to Darren Kearney, 21 October 2010.

Table L.32 AER conclusion on ESV levy step change ($'000, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	193	385	385	385	385	**1734**
Powercor	430	861	861	861	861	**3873**
JEN	189	379	379	379	379	**1705**
SP AusNet	379	759	759	759	759	**3415**
United Energy	398	796	796	796	796	**3584**

Source: AER analysis; ESV, Email from Paul Fearon to Darren Kearney, 21 October 2010.

L.5.2 Environmental obligations

L.5.2.1 Environment Protection (Industrial Waste Resource) Regulations 2009

AER draft decision

The AER did not accept JEN's and United Energy's claims for an external consultant to undertake an assessment of alterative approaches to treating prescribed industrial waste (PIW) in accordance with the requirements of the Environment Protection (Industrial Waste Resource) Regulations 2009.[145] The AER stated that after discussions with the Environment Protection Agency Victoria (EPA), and its own analysis, the AER considered that no material change to the operating environment would be incurred in the transition from the previous regulations to the new regulations.[146] The AER noted that the new Environment Protection (Industrial Waste Resource) Regulations created greater flexibility and incentives for the treatment of PIW but themselves do not prescribe an increase in costs to do so. The AER further noted that the EPA's Sustainable Solutions Unit already provides advice and funding to businesses to better assess and treat waste. The AER also noted that better treatment of waste, including recycling and reusing, can reduce the costs of purchasing new materials and also noted that any business process improvements which resulted in lower costs would be self financing as the net costs should be expected to be less than those reflected in the opex allowance.

The AER also did not accept JEN's initial regulatory proposal that it would experience an increase in costs for the treatment of category B PIW.[147] JEN in its proposal provided a detailed cost-build up of the relevant costs and referred to the Environment Protection (Industrial Waste Resource) Regulations and the Victorian Government's *2010 Statement of Government intentions* (2010 annual statement) as the drivers for the proposed cost increase.[148] The AER noted that the Environment Protection (Industrial Waste Resource) Regulations did not force a material change in category B PIW producer's treatment of waste to landfill. The AER also noted that the increased levies announced in the 2010 annual statement did not apply to the landfill

145 AER, *Victorian draft decision, Appendix L*, June 2010, pp. 173–175.
146 *Previous regulations: Environment Protection (Prescribed Waste) Regulations 1998*; *Industrial Waste Management Policy (Prescribed Industrial Waste) 2000*.
147 AER, *Victorian draft decision, Appendix L*, June 2010, p. 175.
148 JEN, response to information requested on 22 January 2010, 5 March 2010.

levy for category B PIW. These were increased in 2008 in line with the Victorian Government's commitment to zero hazard waste by 2020.

Victorian DNSP revised regulatory proposals

JEN and United Energy did not accept the AER's draft decision regarding their proposed step changes for consultant studies on waste management.

JEN submitted that there is a material change in the assessment of waste under the Environment Protection (Industrial Waste Resource) Regulations 2009 compared to the previous Environment Protection (Industrial Waste Resource) Regulations 1998 and therefore proposed that this step change reflects the efficient costs a prudent operator would require in meeting the opex objectives, particularly NER clause 6.5.6(a)(2).[149] Specifically JEN noted that it was not required to undertake assessments of waste avoidance, treatment or reuse options under the previous regulations. JEN also noted that the HazWaste Fund is not a viable option as it is not guaranteed to secure funding through this avenue and presumed that it will be competing with hundreds of businesses for such funding. JEN further noted that it does not have the internal capabilities to undertake these assessments and therefore an external consultant is required.

With respect to the proposal for the disposal of prescribed waste step change, JEN did not accept the draft decision and proposed $1.8 million in its revised regulatory proposal.[150] Although JEN agreed that the levies announced in the 2010 annual statement did not apply to the landfill levy for category B PIW, it stated that in line with the Victorian Government's commitment to zero hazard waste by 2020 that there is still a 'significant' risk that levies would be increased during the forthcoming regulatory control period. JEN further noted that part of the proposed expenditure for this step change was for additional costs for the ongoing waste management assessments after the initial consultant studies, as the Environment Protection (Industrial Waste Resource) Regulations 2009 have changed the way waste is assessed. JEN noted that this proposal reflects a change in regulatory obligations and is therefore reflective of the opex objectives, particularly NER clause 6.5.6(a)(2).

United Energy stated that it had proposed this step change because it was neither part of any outsourcing arrangement nor any internal expenditure forecasting. United Energy noted that it intends to undertake these assessments and therefore should be provided with expenditure to do so.[151] United Energy stated that other DNSPs had been provided with allowances for similar assessments.

Issues and AER considerations

Consultant studies on waste management

In relation to JEN's and United Energy's proposals for this step change, the AER considers that the proposals are consistent with total forecast opex that reasonably reflect the opex criteria. The AER considers this because the actual opex in the 2006–10 regulatory period did not include these costs, and that these costs reasonably reflect the efficient costs that a prudent operator in the circumstances of JEN and

149 JEN, *Revised regulatory proposal, Appendix 7.2, confidential,* pp. 24–26.
150 JEN, *Revised regulatory proposal, Appendix 7.2, confidential*, pp. 41–42.
151 United Energy, *Revised regulatory proposal 2011–15*, July 2010, p. 92.

United Energy would require in the forthcoming regulatory control period in meeting its regulatory obligations.[152]

The AER notes that contrary to United Energy's revised regulatory proposal, the AER has not previously provided allowances for similar assessments for the other Victorian DNSPs.

However, after further discussions with the EPA and conducting its own analysis, the AER recognises that it is possible that some additional costs may be incurred due to obligations in the Environment Protection (Industrial Waste Resource) Regulations 2009 (new regulations). These occur particularly in relation to the increased emphasis in the new regulations towards reducing the amount of waste inappropriately disposed of.[153] The EPA consider that this should be achieved through a better definition of prescribed waste and tracking and record keeping requirements set out in the new regulations. The AER recognises that the EPA's regulatory impact statement on the new regulations confirmed that additional costs could be incurred in its compliance with reducing the amount of waste inappropriately disposed of.[154]

Further to this, the AER acknowledges JEN's concerns that there is considerable uncertainty in securing funds through the EPA's HazWaste Fund.[155] The AER notes through its discussions with the EPA that it was acknowledged that the HazWaste Fund applicants are assessed on a case by case basis and thus there was no guarantee that funding would be secured. While there is some uncertainty about the securing of funding through the HazWaste fund, the AER considers that this does not detract from the position that costs will be incurred in meeting this regulatory obligation.

For these reasons, the AER accepts JEN's and United Energy's proposals for this step change.

Disposal of prescribed waste

In relation to JEN's proposal regarding the significant risk of the Victorian Government increasing waste disposal levies at any time, the AER disagrees as although the 2010 annual statement noted that increased landfill levies would increase progressively from 2010 to 2014–15, these increases were exclusive of landfill levies for PIW which were increased in 2008.[156] The AER considers that the benchmark opex that would be incurred by an efficient DNSP in meeting this obligation would already be incurred in the 2006–10 regulatory period and therefore should be in their base opex.[157] Further, JEN has not submitted anything in either its initial or revised regulatory proposals to the AER which demonstrated or justified the credibility of such a risk. Neither is the AER aware of anything else which might demonstrate this as a risk in the forthcoming regulatory control period.

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152 NER, clause 6.5.6(c), 6.5.6(e)(4) and (5).

153 EPA, *Regulatory impact statement: Draft environment protection (Industrial waste resource) regulations*, March 2009, pp. 54–55.

154 EPA, *Regulatory impact statement: Draft environment protection (Industrial waste resource) regulations*, March 2009, pp. 54–55.

155 JEN, *Revised regulatory proposal*, Appendix 7.2, p. 25.

156 Minister for Environment and Climate Change, *The new era of recycling and new jobs for Victoria*, www.premier.vic.gov.au/component/content/article/9872.html, 24 March 2010, accessed 6 October 2010.

157 NER, clause 6.5.6(e)(4) and (5).

In relation to JEN's revised regulatory proposal that this step change also reflects costs for ongoing waste management consultant studies, the AER notes that the detailed cost build-up provided as part of JEN's initial regulatory proposal did not refer to any relevant costs for consultant studies.[158] Rather, that the cost build-up referred to the proposed increases in unit rates for waste disposals only.[159] The AER notes that JEN had not submitted anything in its revised regulatory proposal to the AER which demonstrated or justified otherwise.

In JEN's revised regulatory proposal, the AER considers that there has been no change to its initial regulatory proposal. For these reasons the AER's maintains its view in the draft decision that there are no aspects of the Environment Protection (Industrial Waste Resource) Regulation 2009 that would drive large increases in a 'business as usual' treatment of waste, particularly in relation to the unit rates of waste to landfill for a DNSP.

AER conclusion

For the reasons discussed above, the AER considers its estimates set out in table L.33 are part of a total forecast opex that reasonably reflects the opex criteria.

Table L.33 AER conclusion on environmental obligations ($'000, 2010)

JEN	United Energy
0.2	0.2

Source: AER, analysis.

L.5.2.2 National Greenhouse and energy reporting scheme (NGERS)

AER draft decision

The AER acknowledged that the NGERS represents a regulatory obligation for which mandatory compliance is required. However, given compliance with the NGERS was required, and achieved, during the 2006–10 regulatory period, the AER considered that these costs have already been included in both JEN's and United Energy's base year expenditure.[160]

Accordingly, the AER did not accept JEN's and United Energy's proposed additional expenditure, $0.04 million ($2010) and $0.2 million ($2010) respectively, for increased external auditing associated with the NGERS.

Victorian DNSP revised regulatory proposals

JEN acknowledged that it considered it had complied with the NGERS obligations in 2009. However, JEN added that:[161]

> … unless it [JEN] engages a registered external NGERS auditor, it cannot test with confidence whether NGERS compliance has in fact been achieved.

158 JEN, *Revised regulatory proposal*, Appendix 7.2, p. 42; JEN, response to information requested on 22 January 2010, 5 March 2010.
159 JEN, response to information requested on 22 January 2010, 5 March 2010.
160 AER, *Draft decision*, Appendix L, p. 176.
161 JEN, *Revised regulatory proposal*, Appendix 7.2, p. 31.

Further, JEN considered that consistent with the NER, specifically clause 6.5.6(a)(2), engaging a properly accredited external auditor is a prudent response, given the complex nature and continual development of the NGERS.[162] As the NGERS auditing framework was not finalised until late 2009 though, JEN stated that it could not engage a properly accredited external auditor during the base year.[163]

United Energy also disagreed with the AER's draft decision, stating that the step change was not included in the scope of outsourced work that was tendered, nor was it included in United Energy's in-house opex forecasts.[164]

Issues and AER considerations

The AER notes that an external audit is not a requirement of the NGERS, a point acknowledged by JEN in that it was compliant with its obligations under the NGERS in 2009 without undertaking such an audit.[165] The AER, therefore, considers that any additional allowance for compliance with the NGERS cannot form part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs that a prudent operator in the circumstances of JEN would require to comply with the NGERS.[166]

Regarding United Energy, the AER acknowledges that a bottom-up build of costs has been undertaken by United Energy, and that the costs of engaging external auditors has not been included in the tendered costs to service United Energy's network.

The AER, however, has assessed United Energy's regulatory proposal in accordance with a revealed costs approach. As such, a base year opex amount has been derived from a combination of Jemena Asset Management's 2008 regulatory accounts and United Energy's internal cost models.[167] Consistent with the AER's draft decision, the AER considers that these base year costs capture the normal ongoing operating costs of United Energy, which would include the NGERS compliance costs.[168] The AER, therefore, considers that any additional allowance for compliance with the NGERS cannot form part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs that United Energy would require to comply with the NGERS.[169]

AER conclusion

For the reasons discussed above, the AER is not satisfied that the increased external auditing costs associated with the NGERS, as proposed by JEN and United Energy, form part of a total forecast opex that reasonably reflects the opex criteria.

162 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 31.
163 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 31.
164 United Energy, *Revised regulatory proposal*, p. 94.
165 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 31.
166 Consistent with NER, cl. 6.5.6(c)(2) and 6.5.6(a)(2).
167 Refer to appendix I for further discussions regarding the AER's approach to assessing United Energy's proposed opex forecasts.
168 AER, *Draft decision*, Appendix L, p. 176.
169 Consistent with NER, cl. 6.5.6(c)(2) and 6.5.6(a)(2).

L.5.3 Climate change

L.5.3.1 AER draft decision

In the opex base year of 2009 the DNSPs experienced more days of extreme heat and wind than forecast by AECOM for each year of the forthcoming regulatory control period. Consequently, the AER concluded that the costs associated with these extreme weather events will be reflected in the actual opex of the Victorian DNSPs in 2009, which was used as the base year for setting their opex requirements for the forthcoming regulatory control period.[170]

Consequently the AER did not approve a step change for any of the Victorian DNSPs for the impact of climate change. [171]

L.5.3.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor, JEN and SP AusNet did not include a step change for the impact of climate change in their revised regulatory proposals.[172]

United Energy included in its revised regulatory proposal step changes for changes to bushfire risk management due to climate change, climate change studies and increased supply restoration costs due to climate change.[173] The proposed step change amounts were consistent with the amounts proposed in United Energy's initial regulatory proposal.[174]

L.5.3.3 Issues and AER considerations

As noted above, United Energy proposed three step changes to account for climate change impacts. These step changes are discussed below.[175]

Increased supply restoration costs due to climate change

The step change included in United Energy's revised regulatory proposal for increased supply restoration costs due to climate change was the same amount included in its initial regulatory proposal.[176] The amount proposed of $1.3 million per year was consistent with the cost impact of extreme wind events estimated by AECOM.[177] In the draft decision the AER noted, however, that AECOM's cost estimate was calculated using a reference year of 2008, not the opex base year of 2009.[178]

AECOM analysed the AER's assessment of the impacts of climate change in the draft decision. This assessment was attached to United Energy's revised regulatory

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170 AER, *Draft decision*, Appendix L, p. 186.
171 AER, *Draft decision*, Appendix L, p. 186.
172 CitiPower, *Revised regulatory proposal*, p. 177; Powercor, *Revised regulatory proposal*, p. 167; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 65; SP AusNet, *Revised regulatory proposal*, p. 234.
173 United Energy, *Revised regulatory proposal*, pp. 88–91.
174 United Energy, *Regulatory proposal*, Appendix B-7, pp. 4–5.
175 United Energy, *Revised regulatory proposal*, pp. 88–91.
176 United Energy, *Revised regulatory proposal*, pp. 88–91.
United Energy, *Regulatory proposal*, Appendix B-7, pp. 4–5.
177 United Energy, *Regulatory proposal*, Appendix B-7, p. 5; AECOM, *Assessment of climate change impacts on United Energy Distribution network for 2011–2015 EDPR*, September 2009, pp. 44–45.
178 AER, *Draft decision*, Appendix L, p. 177.

proposal. AECOM concluded that the projections of extreme heat and wind, and lightning strikes for the forthcoming regulatory control period were in line with those experienced in 2009. Consequently, AECOM considered that the Victorian DNSPs' opex requirements for the forthcoming regulatory period relating to these events would be in line with their opex relating to these events in 2009.[179] The AER notes that AECOM did not provide updated analysis calculating the cost impacts of extreme heat, wind and lightning using a reference year of 2009. The AER considers that if this analysis was undertaken it would likely indicate cost decreases.

United Energy stated that it required additional opex for supply restoration costs due an increasing frequency of faults due to asset failure. It stated that because the AER did not provide United Energy in the draft decision the replacement capex it proposed it arguably required further opex to address the increased frequency of asset failures.[180]

The AER notes that it has increased the replacement capex determined for United Energy, as discussed in appendix P of this final decision. The AER considers that the forecast capex provided to United Energy is sufficient for it to at least maintain its current level of asset faults. Consequently the AER considers that United Energy has sufficient forecast opex in its base year opex for supply restoration costs.

Consequently, the AER considers that the costs associated with extreme weather events will be reflected in the opex incurred by United Energy and the other Victorian DNSPs in 2009, which is used as the base year for setting their opex requirements for the forthcoming regulatory control period.

Changes to bushfire risk management

The step change included in United Energy's revised regulatory proposal for changes to bushfire risk management was the same amount as included in United Energy's initial regulatory proposal.[181] The total amount of $2.4 million ($2010) proposed by United Energy was forecast by AECOM.[182]

In the draft decision the AER noted that AECOM's estimate of the cost of extreme risk fire days measured the difference between the average number of days for 1973–2006 and the projected number of days for 2020.[183] Similarly, the AER noted that AECOM's estimate of the cost impact of longer fire seasons did not compare the length of the fire season in the opex base year to the projected fire season lengths for the forthcoming regulatory control period.[184]

Responding to the draft decision, AECOM noted that it had earlier advised the AER that 'the additional cost increase attributed to "increase in extreme fire risk days"

179 AECOM, *United Energy revised regulatory proposal*, Appendix C-14, pp. 1–3.
180 United Energy, *Revised regulatory proposal*, p. 91
181 United Energy, *Revised regulatory proposal*, p. 88.
United Energy, *Regulatory proposal: Appendix B-7*, p. 5.
182 AECOM, *Assessment of climate change impacts on United Energy Distribution network for 2011–2015 EDPR*, September 2009, p. viii.
183 AER, *Draft decision*, Appendix L, p. 181.
184 AER, *Draft decision*, Appendix L, p. 181.

should be revised to zero'.[185] AECOM also projected the length of the fire season to reduce from 4.7 months in 2008–09 to 4.6 months 2014–15.[186]

Consequently the AER considers that United Energy's base year expenditure is sufficient to maintain its network given the forecast changes in the length of the fire season over the forthcoming regulatory control period.

The AER notes that United Energy's proposed step change for changes to bushfire risk management also includes costs for the management of hazard trees. These costs were estimated by AECOM and included costs for 'conducting surveys to identify hazard trees and undertaking pruning or other activities to reduce the threat they pose to network assets'.[187] The AER notes that United Energy also included a step change in its revised regulatory proposal for the management of hazard trees as part of its proposed line clearance step change.[188] The AER considers that these two step changes relate to the same activity. The AER has considered the cost impact of managing hazard trees in its consideration of the cost impact of the Electricity Safety (Electric Line Clearance) Regulations 2010 in section L.5.1.2.

Climate change studies

United Energy included the same step change for climate change studies in its revised regulatory proposal that it included in its initial regulatory proposal.[189]

The AER notes that United Energy stated in its revised regulatory proposal that:

> The proposed climate change studies will provide information to the company to ensure that operating and capital expenditure is deployed as efficiently as possible to address and mitigate the impacts of climate change. UED notes that other DNSPs have received an expenditure allowance for these activities.[190]

The AER does not dispute that the proposed climate change studies may provide information to United Energy that would enable it to operate and invest in its network more efficiently. However, the AER notes that United Energy has not identified these efficiency savings in either of its regulatory proposals.

Further, the AER notes that in the draft decision none of the Victorian DNSPs received a step change for climate change studies. The AER is unaware if any of the Victorian DNSPs spent any opex during the base year on such studies.

The AER considers that a prudent DNSP would regularly be undertaking studies on various ways of operating and investing in its network more efficiently. The incentive framework under which the DNSPs operate allows the DNSPs to retain these identified efficiency savings, incentivising them to do so. The AER considers this a normal cost of business and not a step change. The AER considers that the subject of

185 AECOM, *United Energy revised regulatory proposal*, Appendix C-14, p. 4.
186 AECOM, *United Energy revised regulatory proposal*, Appendix C-14, p. 4
187 AECOM, *Assessment of climate change impacts on United Energy Distribution network for 2011–2015 EDPR*, September 2009, p. 75.
188 United Energy, *Revised regulatory proposal*, Appendix B-5, p. 5.
189 United Energy, *Revised regulatory proposal*, p. 88; United Energy, *Regulatory proposal: Appendix B-7*, p. 4.
190 United Energy, *Revised regulatory proposal*, pp. 88–89.

these reports would vary over time. Consequently, even though a DNSP may not have undertaken a study on a particular issue in the past, that does not necessitate that the base year opex does not include the opex required to undertake such a study. Therefore the AER considers that United Energy has sufficient opex in its base year opex to undertake the proposed climate change studies.

L.5.3.4 AER conclusion

For the reasons discussed above the AER is not satisfied that United Energy's proposed step change for the impact of climate change is consistent with a total forecast opex that reasonably reflects the opex criteria.

L.5.4 Insurance

L.5.4.1 AER draft decision

In their initial regulatory proposals, CitiPower, Powercor, SP AusNet and United Energy proposed a total of $54.7 million ($2010) in increased insurance costs over the forthcoming regulatory control period. JEN did not propose a step change in its insurance costs.

CitiPower and Powercor stated that categories of insurance for which they obtain insurance cover included corporate travel, crime, industrial special risk (property), inpatriate, liability, motor vehicle and personal accident. Powercor also obtains insurance for aviation risk.[191] The insurance premium costs in CitiPower's and Powercor's base year (2009) opex are $0.8 million and $2.5 million, respectively. For CitiPower, this represented a step change increase from $0.8 million to $2.8 million per annum between 2009 and 2015. For Powercor, the proposed increase was from $2.5 million to $10.8 million per annum between 2009 and 2015.[192]

SP AusNet stated that its annual insurance premium liability had increased from [commercial in confidence], from September 2009. Since only one quarter of this increase was reflected in its base year (2009) opex, SP AusNet proposed the remaining three quarters ([confidential]) as a step change. In addition, SP AusNet sought an allowance for additional coverage resulting in an additional increase ([commercial in confidence]). The combined effect of these components was a step change of [confidential]per annum.[193]

United Energy noted that its insurance premiums increased from $1.4 million to $2.1 million as of September 2009. Accordingly, United Energy sought a $0.7 million increase in its annual opex forecast as an insurance premium step change.[194]

The AER was not satisfied that CitiPower's and Powercor's proposed insurance premium step changes reasonably reflects the opex criteria.

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191 CitiPower, *Regulatory proposal*, p.170; Powercor, *Regulatory proposal*, p.167.

192 These values were expressed in $2010. The AER converted the values in the Aon report which were expressed in $2009.

193 SP AusNet, *Regulatory proposal—Appendix I 'Electricity distribution network—Incremental opex impact to 2009 base year'*, November 2009, p.15.

194 United Energy, *Regulatory proposal—Appendix B.7*, 30 November 2009.; United Energy, *Regulatory proposal*, Appendix I.7, p. 4.

Of the $16.7 million ($2010) step change proposed by SP AusNet over the forthcoming regulatory control period, the AER was satisfied that $15.0 million ($2010) reasonably reflects the opex criteria. That is, the AER accepted the increased amount to reflect SP AusNet's current actual premiums but not the increased amount associated with the additional insurance coverage.

The AER was satisfied that United Energy's proposed insurance step change of $3.5 million ($2010) reasonably reflects the opex criteria. However, the AER removed the 'double-counting' of this increase in United Energy's opex proposal (by removing it from the opex base forecast).

The AER's draft decision on insurance premium step changes is set out in table L.34.

Table L.34 AER draft decision on insurance premium step changes ($'m, 2010)

CitiPower	Powercor	SP AusNet	United Energy
–	–	15.0	3.5

Source: AER, *Draft decision*, Appendix L, p. 194.

L.5.4.2 Victorian DNSP revised regulatory proposals

SP AusNet accepted the AER's draft decision with regard to the additional insurance costs that SP AusNet incurred from September 2009.[195]

However, on the issue of additional coverage SP AusNet noted that:

> …the AER has sought additional information from SP AusNet in support of this Step Change, and in particular, "details about the calculation of the maximum probable loss exercise". SP AusNet has finalised this work for input into this regulatory process. It is noted that SP AusNet's Maximum Foreseeable Loss exercise supports a $[c-i-c] increase in its insurance limits. This document is provided as supporting documentation to this Revised Proposal.
>
> The additional cost of taking out this external insurance coverage is estimated to be [c-i-c] [per annum]. This is based on a considered estimate by SP AusNet's insurance broker, Marsh, after having regard for the different layers of coverage required to reach the capacity SP AusNet requires, the different markets available to source that coverage, and the different premium costs associated with coverage in those different markets. In addition, SP AusNet notes that it also sought information from Marsh in relation to the liquidity of the overall market for insurance, up to, this limit. In short, Marsh has indicated that the market for insurance up to this limit is considered liquid.[196]

CitiPower and Powercor noted the AER's draft decision on insurance premium step changes.[197] However, they raised concerns with the AER's approach to assessing their insurance step changes. Specifically, they submitted that the AER had accepted, in the

[195] SP AusNet, *Revised regulatory proposal*, p. 211.
[196] SP AusNet, *Revised regulatory proposal*, p. 212.
[197] CitiPower, *Revised regulatory proposal*, pp. 21, 190–191; Powercor, *Revised regulatory proposal*, pp. 180–181.

South Australian distribution determination for ETSA Utilities, a step change for insurance premiums.[198]

CitiPower and Powercor also submitted that they would accept a step change that reflects the difference between their 2009 and 2010 external insurance premiums. However, this information was not available at the time the regulatory proposals were submitted.

CitiPower and Powercor provided the relevant insurance invoices to the AER on 30 September 2010. In their revised regulatory proposals, both had used a placeholder assumption for the insurance step changes, based on a 15 per cent increase in the insurance premiums reported in the 2009 regulatory accounts.[199]

The updated premiums that were submitted by CitiPower and Powercor showed that:

- CitiPower's insurance premiums had increased from [confidential] in 2009 to [confidential] in 2010
- Powercor's insurance premiums had increased from [confidential]in 2009 to [confidential]in 2010.[200]

United Energy accepted the AER's draft decision on insurance premiums.[201]

L.5.4.3 Issues and AER considerations

In considering whether or not to accept the insurance step changes proposed by the Victorian DNSPs, the AER notes that the operating expenditure objective contained in clauses 6.5.6(a)(3) and (4) of the NER—that is, to maintain the quality, reliability and security of supply of standard control services and to maintain the reliability, safety and security of the distribution system through the supply of standard control services—is particularly relevant. The AER considers, at a high level, the provision of insurance is an accepted risk mitigation tool that service providers can use to provide protection for events that may undermine the provision of standard control services. In considering the actual insurance premiums proposed by the Victorian DNSPs, the AER notes that the opex criterion in cl. 6.5.6(c)(3)—the realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives is also particularly relevant.

The AER considers that insurance premiums are a cost input contributing to the achievement of the opex objectives. The AER has further considered the insurance premiums against the opex factors, particularly cl. 6.5.6(e)(5), which references the actual and expected operating expenditure of the DNSP during any preceding regulatory control periods. This is relevant to increased insurance premiums, as step changes sought for increased premiums are measured against the incurred premiums in the 2006–10 regulatory control period. The AER has also considered the information provided with the building block proposal, and subsequent submissions

198 ibid.
199 ibid
200 CitiPower/Powercor, Response to information requested 9 September 2010, 30 September 2010.
201 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015,* July 2010, p. 90.

received from CitiPower and Powercor in response to information requests by the AER.[202]

CitiPower and Powercor

CitiPower and Powercor both provided updated insurance invoices to the AER on 30 September 2010. These invoices reflected actual premiums that will be incurred by both CitiPower and Powercor in the forthcoming regulatory control period.

These invoices show that the increased premiums for 2009–10:

- for CitiPower, an increase of [confidential]
- for Powercor, an increase of [confidential]

The AER accepts that these costs are reflective of actual insurance premiums for CitiPower and Powercor, and are a reasonable basis for estimating insurance premiums over the forthcoming regulatory control period. The AER's draft decision noted that:

> If Powercor submits its 2010 bushfire liability premiums with its revised proposal, then the AER may be satisfied that the difference between its 2009 and 2010 premiums reflect a realistic expectation of costs inputs over the forthcoming regulatory control period.[203]

The AER is satisfied that an increase in insurance premiums of [confidential]for CitiPower and [confidential]for Powercor represents a realistic expectation of costs inputs over the forthcoming regulatory control period.

The AER considers that the increased premiums proposed by CitiPower and Powercor are consistent with a total forecast opex that reasonably reflects the opex criteria. Namely, the AER accepts that these increased premiums reflect changes in the market for insurance in which CitiPower and Powercor must obtain coverage for insurable risks. This is therefore a realistic expectation of the cost of insurance required (insurance being a relevant cost input for the purposes of cl. 6.5.6(c)(3) of the NER). The AER further considers that these costs reflect that which a prudent operator in the circumstances of the DNSP would require to achieve the operating expenditure objectives (cl. 6.5.6 (3) (b) of the NER), in that it is reasonable for a service provider to seek insurance to insulate itself against activities or events that may threaten the security and reliability of the provision of direct control services.

Accordingly, the AER is satisfied that CitiPower's and Powercor's proposed step change is a realistic expectation of cost inputs over the forthcoming regulatory control period, in accordance with cl. 6.5.6(c)(3) of the NER, and is therefore consistent with a total forecast opex that reasonably reflects the opex criteria. For these reasons the AER has accepted the difference between 2009 premiums and 2010–11 premiums as step changes for CitiPower and Powercor. Therefore, the AER approves a step change of [confidential] for CitiPower and [confidential] for Powercor.

[202] Consistent with the NER, cl. 6.5.6(e)(1) and (2).
[203] AER, *Draft decision*, Appendix L, p. 192.

SP AusNet

In assessing SP AusNet's proposed insurance premium step change, the AER has had regard to the same criteria, objectives and factors as for CitiPower and Powercor. The AER considers that these are also relevant to the assessment of SP AusNet's insurance premiums.

SP AusNet proposed an increase in insurance premiums of $2.4 million per annum. In proposing these increased premiums, [commercial in confidence, commercial in confidence].[204]

[commercial in confidence]:

> … [commercial in confidence]
>
> [commercial in confidence][205]

[commercial in confidence,

[commercial in confidence].[206]
[commercial in confidence].[207]

[commercial in confidence].[208]

The AER understands that this is the basis for SP AusNet's proposed insurance step change of [confidential].[209] In its revised regulatory proposal, SP AusNet also stated that there is no double counting between its increased external insurance coverage, and the cost pass through event provision for an 'insurance event'.[210] It further considered that these mechanisms would work together to ensure that SP AusNet adopts the most efficient risk management approach. SP AusNet further stated that risk mitigation is a mix of various factors, including:

- liquidity of the market for insuring that risk
- whether that risk is specific to the business, or is common across multiple businesses
- the probability distribution of outcomes associated with that risk (mean, standard deviation).[211]

204 [confidential]
205 [confidential], pp. 2-3.
206 [confidential], p. 1.
207 ibid., p. 2.
208 ibid.
209 SP AusNet, *Revised regulatory proposal*, p. 212. The additional $30 000 represents statutory charges.
210 ibid, p. 213.
211 ibid.

SP AusNet noted that where coverage is sought above a reasonable level (reflecting the moral hazard risk), and the insurance market is liquid, then pooling benefits generally result in external insurance being the most efficient mechanism for managing such risks.[212] SP AusNet considered this to be the case for its proposed increase in liability premiums.

The AER notes that it has, as part of this final decision, provided a pass through event for above insurance cap events. Consequently, customers will bear the risk of costs incurred by a DNSP in excess of its insurance coverage. The AER also notes that customers will effectively bear the costs of increased insurance premiums if they are granted through SP AusNet's opex allowance. Therefore, the AER considers that SP AusNet would be compensated for such a loss, either through an external insurance policy or a combination of external insurance and the insurance cap pass through event outlined in this final decision (see chapter 16).

If the current insurance policy limits remain in place, that is, [c-i-c], then where an above cap insurance event occurs, customers could be expected to bear all incurred pass through costs above [confidential]. If the maximum loss event calculated by Marsh in its MFL study eventuated ([confidential]), then the pass through costs to customers would [confidential].

Conversely, if the new policy limits are implemented, then customers may not be exposed to pass through costs above the insurance cap (using the assumption of the MFL study again, a cost event totalling [confidential]). However, customers will be exposed to an extra [confidential] per annum in premiums through SP AusNet's opex.

As noted above, the AER considers that SP AusNet is protected from such risks in either scenario. The subsequent issue is to determine the appropriate mechanism for recovery of these costs in the event of such liability. SP AusNet considered that external insurance, in this instance, is the most efficient mechanism for managing the risk. The approach taken by the AER in relation to bushfire liability risk compensates SP AusNet for the full spectrum of this risk exposure through:

- a self insurance allowance in the opex forecast for the below-deductible amount
- an insurance premium allowance in the opex forecast for the insured exposure
- a pass through event for the exposure greater than that insured.

Given this consideration, the AER has not identified any reasons that would suggest SP AusNet does not have an incentive to choose the most efficient mix of risk mitigation mechanisms, and therefore, the AER accepts SP AusNet's statement that external insurance is preferable in this instance.

[commercial in confidence].[213]

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212 ibid.
213 See, Marsh letter to SP AusNet from Marsh Risk Consulting, 2 July 2010.

[commercial in confidence].

On this basis, the AER is satisfied that SP AusNet's proposed step change of $2.4 million per annum is consistent with a total forecast opex that reasonably reflects opex criteria.

The AER considers that the increased premiums proposed by SP AusNet reasonably reflect the opex criteria and objectives. Namely, the AER accepts that these increased premiums reflect changes in the market for insurance in which SP AusNet must obtain coverage for insurable risks, and accepts the increased coverage as an accepted method of risk mitigation that SP AusNet reasonably expects to face on its network.

This is therefore a realistic expectation of the cost of insurance required (insurance being a relevant cost input for the purposes of cl. 6.5.6 (c) (3) of the NER). The AER further considers that these costs reflect that which a prudent operator in the circumstances of the DNSP would require to achieve the operating expenditure objectives (cl. 6.5.6 (3) (b) of the NER), in that it is reasonable for a service provider to seek insurance to insulate itself against activities or events that may threaten the security and reliability of the provision of direct control services.

L.5.4.4 AER conclusion

For the reasons discussed above, and as a result of the AER's consideration of CitiPower's, Powercor's, SP AusNet's and United Energy's revised regulatory proposals and other supporting information, the AER is satisfied that all of their proposed insurance premium step changes form part of a total forecast opex that reasonably reflects the opex criteria. In coming to this view the AER has had regard to the opex factors.

The step changes approved are set out in table L.35 reflect expenditure that reasonably reflects the efficient costs of a prudent operator and is the minimum adjustment necessary for opex to comply with the NER.

Table L.35 AER conclusion on insurance premium step changes ($'m, 2010)

CitiPower	Powercor	SP AusNet	United Energy
0.7	2.8	26.9	3.5

Source: AER analysis

L.5.5 National framework for distribution network planning and expansion

L.5.5.1 AER draft decision

At the request of the Ministerial Council on Energy (MCE), the Australian Energy Market Commission (AEMC) provided advice to the MCE on streamlining the regulatory investments test for distribution (RIT-D), as well as distribution planning requirements generally. The AEMC released its proposed draft rules to enact the RIT-D provisions in September 2009.[214]

The AER's draft decision concluded that the AEMC had advised the MCE on the implementation of the RIT-D and that it was likely to commence operation in 2011. The AER determined opex step changes for each of the Victorian DNSPs for the introduction of the new national framework for distribution planning and expansion as outlined in table L.36.

The AER notes, however, that the draft decision preceded any MCE response to the AEMC's final advice and draft rule change.

Table L.36 AER draft decision on national framework expenditure ($'m, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
2.7	4.3	0.6	1.9	1.4

Source: AER, *Draft decision*, Appendix L, p. 197.

L.5.5.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs agreed with the AER's draft decision on the proposed new national framework for distribution planning and expansion.

JEN also advised that it had inadvertently excluded from its initial regulatory proposal:

- distribution annual planning review (DAPR) requirements to cover activities associated with replacement assets
- an explanation for the updated forecasts from the previous years DAPR.
- the requirement to carryout regulatory investment tests for transmission connection augmentations at SP AusNet terminal stations, in addition to RIT for distribution augmentations
- the cost of engaging consultants to undertake the regulatory investment tests
- additional resources for dispute resolution during the RIT process.[215]

JEN estimated that the incremental cost to meet these new requirements was $0.95 million ($2010). JEN estimated that it would cost $1.49 million ($2010) in total to meet all RIT-D and distribution planning obligations.[216]

L.5.5.3 Issues and AER considerations

Although the MCE has yet to formally affirm the AEMC's advice, this is seen by the AER as a formality. The AER noted in the draft decision that:

214 Australian Energy Markets Commission, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009.
215 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 22–23.
216 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 24.

- if the MCE accepts AEMC's final report, the AEMC's draft framework and draft rule changes are expected to undergo consultation in 2010, with the final rule changes to follow

- AEMC representatives confirmed to AER staff that if the rule change is accepted, new obligations are expected to be imposed on DNSPs during 2011.[217]

The AER concluded that it was sufficiently certain that the RIT-D would be implemented and effective from 2011. Even if delayed, it is anticipated to begin during the 2011–15 regulatory control period.

The AER has reviewed the incremental costs included in JEN's revised regulatory proposal in light of the AEMC's final recommendations and the other DNSPs' initial regulatory proposals.

The AER has observed that the obligations noted by JEN formed part of the AEMC's recommendations on requirements to be imposed on DNSPs to meet the RIT-D and distribution planning regime. Further, other DNSPs' initial regulatory proposals contained forecasts to meet these obligations, which the AER's draft decision accepted.

On this basis, the AER considers that the additional step change forecast proposed by JEN reasonably reflects the costs that it will incur to comply with the national framework for distribution planning and expansion.

L.5.5.4 AER conclusion

For the reasons discussed above the AER is satisfied that the Victorian DNSPs' proposed expenditure to comply with the national framework for distribution planning and expansion, as set out in table L.37, is consistent with a total forecast opex that reasonably reflects the opex criteria.[218].

Table L.37 AER conclusion on national framework expenditure 2011–15 ($'m, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
2.7	4.3	1.5	1.9	1.4

Source: AER analysis

L.5.6 Customer communications

L.5.6.1 Customer charter

AER draft decision

The *Electricity Distribution Code* (EDC) requires DNSPs to provide all customers at least once every five years and new customers connected to the distribution network annually, a customer charter that sets out the respective rights and obligations of distributors and customers for the supply of electricity. The charter must include the

[217] AER, *Draft decision*, Appendix L, p. 195.
[218] Consistent with the NER, clause 6.5.6(a)(2).

distributors name, guaranteed service levels and the impact of codes, guidelines and regulations on the customer–distributor relationship.[219]

The AER determined a step change for the Victorian DNSPs to print, distribute and mail the customer charter to their network customers as outlined in table L.38. The AER observed that this expenditure was a non-recurrent cost not in the base opex of the Victorian DNSPs.

SP AusNet did not propose any customer charter costs in its original proposal.

Table L.38 AER draft decision on customer charter expenditure ($'m, 2010)

CitiPower	Powercor	JEN	United Energy
0.3	0.7	0.5	0.6

Source: AER, *Draft decision*, Appendix L, p. 203.

DNSP revised regulatory proposals

CitiPower, Powercor and JEN accepted the AER's draft decision, however CitiPower and Powercor sought real cost escalation over the forthcoming regulatory control period.[220]

SP AusNet proposed forecast expenditure of $0.6 million ($2010) in its revised regulatory proposal, having not proposed any costs in its initial regulatory proposal.[221]

United Energy rejected the AER's draft decision of $0.7 million and proposed $1 million, consistent with its initial regulatory proposal. It stated that the basis for the AER reducing its proposed customer charter expenditure was unclear.[222]

Issues and AER considerations

The AER notes that CitiPower, Powercor and JEN have proposed step changes for preparing and distributing their customer charter consistent with the AER's draft decision.

The AER notes that its draft decision for United Energy excluded the costs of glow in the dark fridge magnets, which United Energy had proposed. The AER considered that the provision of fridge magnets exceeded the obligations on distributors under the code.[223] United Energy stated that magnets provided useful illuminated information, such as call centre and websites contacts, during power outrages.[224]

The AER considers that information on magnets (such as phone numbers) duplicates that already available in the customer charter and, to a degree, on retail bills.

[219] ESCV, *Electricity distribution code*, February 2010, p. 25.
[220] CitiPower, *Revised regulatory proposal*, p. 211; Powercor, *Revised regulatory proposal*, p. 200; JEN, *Revised regulatory proposal, Appendix 7.2l*, p 10.
[221] SP AusNet, *Revised regulatory proposal*, p. 239.
[222] United Energy, *Revised regulatory proposal*, July 2010, p. 86.
[223] AER, *Draft decision*, Appendix L, June 2010, p. 202.
[224] United Energy, *Revised regulatory proposal*, p. 86.

It is notable that during power outages a sufficient number of calls are received by the DNSPs' call centres to advise them of power outages, enabling the DNSPs to take corrective action. Furthermore, the AMI rollout will provide DNSPs with greater information on the incidence of localised power outages without the need to be alerted by customers.

For these reasons, the AER maintains that United Energy's proposed step change for customer charter costs does not reasonably reflect the efficient costs that a prudent operator requires to comply with the EDC or to maintain the reliability of its network.[225] In coming to this view the AER has had regard to the opex factors.[226]

SP AusNet noted the AER's draft decision recognised customer charter costs as a step change for all other Victorian DNSPs. SP AusNet's revised regulatory proposal forecast costs of $0.6 million during the forthcoming regulatory control period and stated that it inadvertently did not include these costs in its initial regulatory proposal.[227]

The AER notes that SP AusNet's revised regulatory proposal sought printing, supply and mailing costs for its customer charter consistent with the AER's draft decision for CitiPower, Powercor and United Energy.

For these reasons, the AER considers that SP AusNet's proposed customer charter expenditure reasonably reflects the prudent and efficient costs that it requires to comply with the EDC.[228]

AER conclusion

For the reasons discussed above, the AER is satisfied that the Victorian DNSPs' proposed customer charter expenditure, with the exception of that proposed by United Energy, is consistent with a total forecast opex that reasonably reflects the opex criteria.[229]

In respect of United Energy's customer charter expenditure, the AER has deducted the costs of glow in the dark fridge magnets from United Energy's revised regulatory proposal. The AER considers that this is the minimum adjustment necessary for United Energy's opex to comply with the NER.

The final decision on customer charter expenditure is set out in table L.39.

Table L.39 AER final conclusion on customer charter expenditure ($'m, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
0.3	0.7	0.4	0.6	0.7

Source: AER analysis.

225 Consistent with clause 6.5.6(a)(2) and (4) of the NER.
226 Specifically opex factors (1) and (3).
227 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 239.
228 Consistent with clause 6.5.6(a)(2) of the NER.
229 Consistent with clause 6.5.6 (a)(2) of the NER.

L.5.6.2 Enhanced customer communications

AER draft decision

The AER noted that the EDC would be amended to require Victorian DNSPs to write to customers each year, informing them of the DNSP's role in maintaining and restoring supply following emergencies, and providing contact details and website addresses.

The AER was not satisfied, however, that the inclusion of costs associated with upgrades to SMS capabilities reasonably reflected the opex criteria. Further, the AER was not satisfied that SP AusNet's proposed step change for enhanced customer communications reasonably reflected the opex criteria.

Table L.40 AER draft decision on communication to customers during outage events expenditure ($'m, 2010)

	JEN	SP AusNet	United Energy
	2.1	–	1.6

Source: AER, *Draft decision*, Appendix L, p. 200.

DNSPs' revised regulatory proposals

CitiPower's and Powercor's revised regulatory proposals noted that on 28 January 2010 they informed the AER of an additional step change in respect of communications in extreme supply events. However, that advice did not propose additional costs to meet these obligations.[230]

CitiPower's and Powercor's revised regulatory proposals, noting earlier letters sent to the AER dated 4 May 2010, proposed costs of $0.8 million ($2010) and $2 million ($2010) respectively.[231]

Both DNSPs noted that the EDC final amendments enacted in February 2010 (and effective from April 2010) clarified their obligations during the forthcoming regulatory control period.[232]

CitiPower and Powercor amended their initial forecast expenditure to $1.5 million ($2010) and $3.4 million ($2010) respectively.[233] These forecasts did not include expenditure for SMS communication.

JEN considered that the AER's draft decision misinterpreted the ESCV's 2009 decision and draft EDC amendments, failed to evaluate its revised estimates submitted in February 2010, was unclear on the quantum of costs rejected and did not consider

[230] CitiPower, *Revised regulatory proposal*, p. 203; Powercor, *Revised regulatory proposal*, p. 192.
[231] CitiPower, *Revised regulatory proposal*, p. 203; Powercor, *Revised regulatory proposal*, p. 192.
[232] CitiPower, *Revised regulatory proposal*, pp. 203–204; Powercor, *Revised regulatory proposal*, pp. 192–193.
[233] CitiPower, *Revised regulatory proposal*, pp. 203-–204; Powercor, *Revised regulatory proposal*, pp. 192–193.

the network and customer benefits associated with SMS. Consequently, JEN proposed $4.6 million ($2010) in step changes for the EDC obligations during 2011–15.[234]

Consistent with its initial regulatory proposal, SP AusNet proposed a step change of $0.9 million ($2010) to initiate a storm preparedness campaign to mange customers' expectations during power outages. SP AusNet also proposed a $3 million ($2010) step change to deliver SMS messages to customers during extreme supply events, in addition to a new step change of $3 million ($2010) for compliance with EDC clause 9.1.2A.[235]

United Energy resubmitted its original $3.7 million ($2010) forecast to meet the EDC's requirements for extreme event management and customer communications. The forecast cost included SMS updates to customers during network outages.[236]

Issues and AER considerations

The ESCV amended the EDC in February 2010 requiring the Victorian DNSPs to inform customers each year in writing of the DNSPs role regarding maintaining and restoring supply following emergencies, and to provide contact details and website addresses. These amendments came into force on 1 April 2010.

The AER considers that these EDC amendments increase the Victorian DNSPs regulatory obligations.

The AER considers that CitiPower's and Powercor's forecast mailing, postage and printing expenses reasonably reflect the efficient costs of a prudent operator to comply with the requirements of the EDC.

JEN considered that the AER's draft decision selectively quoted the ESCV's 2009 decision and inferred that the ESCV prohibited the use of SMS. The AER agrees with JEN that the ESCV did not state that SMS technology should not be used to communicate with customers.

The AER notes that the EDC requires that in the event of an unplanned interruption or emergency:

> … a distributor must within 30 minutes of being advised of an unplanned interruption or emergency, or as soon as practicable, provide by way of 24 hour telephone service and by way of frequently updated entries on a prominent part of its website information on the nature of the interruption and an estimate of the time when supply will be restored…[237]

JEN's revised regulatory proposal stated that it has used a 'basic' SMS facility since December 2009 but considered it insufficient to inform its entire customer base of a widespread unplanned emergency.[238] Therefore, it proposed additional expenditure to upgrade its system.

234 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, 20 July 2010, pp. 27–30.
235 SP AusNet, *Revised regulatory proposal*, pp. 235–237.
236 United Energy, *Revised regulatory proposal*, pp. 87, 94.
237 Electricity distribution code, clause 5.4.1(a), February 2010, pp 16–17.
238 JEN, *Revised regulatory proposal*, p. 30.

JEN estimated the SMS upgrade cost at $0.2 million ($2010). It advised that the $2.1 million ($2010) not accepted by the AER in the draft decision related to the combined expenditure for JEN's Interactive Voice Recognition (IVR) and SMS systems. On this basis, it considered that the AER incorrectly removed IVR expenditure (of $1.9 million).[239]

The AER has taken account of JEN's February 2010 amended expenditure forecast of $4.6 million ($2010) to meet the requirements of the EDC and its claim that only $0.2 million related to SMS technology.

The AER considers that JEN's proposed IVR expenditure is required to meet its regulatory obligations under the EDC. Therefore, that expenditure has been accepted this final decision.

Regarding the $0.2 million step change for SMS proposed by JEN, the AER considers this to be an efficient means of provided the information required by the EDC to JEN's network users and provides an alternative communication method that will potentially reduce demand on JEN's call centre.

The remainder of JEN's proposed expenditure related to ensuring that its IVR system could cope with the additional demands placed on it by customer calls during extreme supply events. The AER has reviewed JEN's communication tools, the proposed upgrades and estimates of higher demand the system was expected to cope with. The AER considers that the associated costs represent the efficient costs required by a prudent operator in the circumstances of JEN to provide the necessary communication to its customers during extreme supply events.

For the reasons discussed above, the AER also accepts that SP AusNet should be funded to deliver SMS services to customers in extreme outage events. However, the AER notes that its forecast opex of $3 million ($2010) considerably exceeds that proposed by JEN and United Energy of $0.2 million ($2010) and $0.4 million ($2010) respectively.

The AER notes that SP AusNet has twice as many customers as JEN but a similar number to United Energy. Taking account of expenditure forecasts by JEN and United Energy, and SP AusNet's revised regulatory proposal, the AER considers that the efficient costs required by a prudent operator in the circumstances of SP AusNet to provide SMS services is $1.5 million.

The AER has also considered SP AusNet's proposed $0.9 million ($2010) to initiate a storm preparedness campaign to manage customers' expectations during power outages. This was in addition to the $3 million ($2010) SP AusNet proposed for compliance with EDC clause 9.1.2A. The AER considered both proposals concurrently in terms of compliance obligations and the outcomes to be delivered by SP AusNet's proposals. The AER considers that the $3 million ($2010) proposed by SP AusNet to comply with the EDC, along with approved expenditure for the customer charter, reasonably reflects the prudent and efficient costs required by SP AusNet to comply with its regulatory obligations under the EDC regarding extreme supply events. Consequently, the AER considers that SP AusNet's forecast

[239] JEN, *Revised regulatory proposal*, p. 27.

$0.9 million for customer communications during storms double counts costs and does not reasonably reflect the efficient expenditure required by SP AusNet to comply with its regulatory obligations under the EDC.

United Energy proposed $3.3 million ($2010) for customer communication associated with mailing printed materials to meet EDC clause 9.1.2A and $0.4 million ($2010) to SMS customers during extreme supply events such as unplanned power outages. In assessing the efficiency of United Energy's proposed expenditure, the AER notes that its expenditure forecast over the 2011–15 regulatory control period exceeds JEN's by 91 per cent, after allowance for United Energy's higher customer numbers. Given the large disparity between the cost proposed by United Energy and JEN, the AER considers that United Energy's proposal does not reasonably reflect the prudent and efficient expenditure required by United Energy to comply with its EDC regulatory obligations. To determine the prudent and efficient costs required by United Energy to comply with its regulatory obligations, the AER adjusted United Energy's proposed costs to account for the difference in customer numbers between United Energy and JEN. Accordingly, the AER concludes that $2 million represents the efficient costs required by United Energy during 2011–15 to meet its EDC obligations. Consistent with its analysis, the AER considers that United Energy's proposed $0.4 million ($2010) for SMS communications reasonably reflect the prudent and efficient costs of complying with its regulatory obligations under the EDC.

AER conclusion

For the reasons discussed above, the AER considers its estimates for enhanced customer communications expenditure in table L.41 are part of a total forecast opex that reasonably reflects the opex criteria.

Table L.41 AER final conclusion on enhanced customer communications expenditure ($'m, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
1.5	3.4	4.6	4.5	2.4

Source: AER analysis.

L.5.6.3 Marketing Communications

AER draft decision

The AER accepted neither JEN's proposal for stakeholder relations (marketing communications) nor United Energy's additional marketing step changes as the businesses had not demonstrated that the proposals were directly related to a specific regulatory trigger or a change in the operating environment.[240]

Victorian DNSP revised regulatory proposals

JEN and United Energy did not agree with the AER's draft decision on their respective marketing communication proposed step changes.[241]

240 AER, *Victorian draft decision,* Appendix L, pp. 227–230, 237–238.

241 JEN, *Revised regulatory proposal,* Appendix 7.2 ,confidential, pp. 9, 62–65; United Energy, *Revised regulatory proposal*, p. 86.

JEN conceded that this step change was not driven by a change in regulatory obligations. Rather, JEN stated that the step change was driven by a change in its operating environment and linked this to the Wilson Cook criteria in the New South Wales final decision.

Specifically, JEN proposed that public awareness and demands have increased since the beginning of the 2006–10 regulatory period and this has caused a significant rise in complaints and inquiries by customers. To ‘proactively’ manage this change in the public environment JEN proposed that additional marketing communications are now required. JEN revised its initial regulatory proposal step change costs down to reflect the removal of coloured advertisements in major newspapers.[242]

United Energy noted that it proposed this step change as its base marketing costs are low in comparison to the other Victorian DNSPs and that it needs to increase its ‘role’ in the community to be consistent with the base year costs of the other Victorian DNSPs.[243]

JEN and United Energy have forecast an allowance of $0.4 million ($, 2010) each for these step changes over the forthcoming regulatory control period.[244]

Issues and AER considerations

The AER does not accept JEN’s and United Energy’s revised proposals because the actual opex incurred in the 2006–10 regulatory period should already include these costs and the proposals do not reflect the benchmark opex that would be incurred by the efficient DNSP in the forthcoming regulatory control period.[245] For the reasons set out below, the AER considers that opex provided to the Victorian DNSPs to meet their regulatory obligations in the forthcoming regulatory control period already includes the efficient costs for these proposals and therefore an additional allowance for marketing communications would be double counting.

In support of its initial regulatory proposal, JEN noted that the primary purpose of the marketing communications step change is:

> …increasing consumer awareness on the electricity industry and the distributors’ role, the increasing supply events every year and steps that should be taken, obligations of each party, vital distribution contact details (call centre, faults, IVR) and alternative communication tools (SMS, Website) that are used for all supply events.[246]

Similarly, United Energy noted:

> The costs of this activity include those associated with customer liaison, engagement with other stakeholder groups and the provision of better information to those groups on various matters such as solar, tariffs, the customer charter etc[247].

[242] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 64.
[243] United Energy, *Revised regulatory proposal*, p. 86.
[244] JEN, *Revised regulatory proposal*, p. 65; United Energy, *Revised regulatory proposal*, p. 86.
[245] NER, clauses 6.5.6(e)(5) and (4).
[246] JEN, Response to information requested 19 February 2010, 10 March 2010, p. 6.
[247] United Energy, *Revised regulatory proposal*, p. 86.

The AER acknowledges that customers are becoming more aware of electricity distribution matters and should be provided with appropriate information. However, the AER notes that similar information to that which JEN and United Energy are proposing under these step changes are also required for JEN's and United Energy's enhanced customer communications proposal to comply with clause 9.1.2A of the Victoria Electricity Distribution Code:

> Prior to the end of December of each year, a distributor must notify each of its customers in writing about its role in relation to maintenance of supply, emergencies and restoration after the interruptions and the distributor's contact details and website address.

The AER further notes that similar information is required to be provided to customers under clause 9.1.3 of the Victoria Electricity Distribution Code, which relates to the provision of the customer charter:

> The distributor's Customer Charter must summarise all current rights, entitlements and obligations of distributors and customers relating to the supply of electricity, including:
>
> (a) the identity of the distributor, and
>
> (b) the distributors guaranteed service levels
>
> and other aspects of their relationship under this Code and other applicable laws and codes.

As United Energy's revised regulatory proposal for additional marketing is directly linked to the customer charter, the AER considers this to be double counting as an allowance for the customer charter for the Victorian DNSPs was provided for in the AER's draft decision and updated in this final decision.[248]

Further, United Energy submitted that its current marketing opex is lower than the other Victorian DNSPs and that this proposal would bring it up to a similar level.[249] However, the AER notes that based on the information provided in the Victorian DNSPs' regulatory information notices, United Energy's opex for advertising and marketing for the 2006–10 regulatory period is the highest of all the Victorian DNSPs and is in the mid range of the proposed expenditure by the Victorian DNSPs for this category in the 2011–15 regulatory control period. Therefore in relation to the benchmark opex that would be incurred by an efficient DNSP in the forthcoming regulatory control period, the AER considers that United Energy's proposal would not be consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria.[250]

With respect to JEN's proposal that part of this step change relates to mail-outs or mail-drops that will be distributed to customers who are likely to be most affected by a predicted supply event, the AER considers the yearly notification as mandated by clause 9.1.2A of the Victoria Electricity Distribution Code not only addresses this issue but incorporates JEN's entire customer base. The AER further considers that

248 United Energy, *Revised regulatory proposal*, p. 86; AER, *Victorian draft decision*, Appendix L, pp. 201–203

249 United Energy, *Revised regulatory proposal*, p. 86.

250 NER, clauses 6.5.6(e)(4); 6.5.6(c).

even though customers will receive JEN's customer charter less frequently, the provision of this information is another opportunity for JEN to provide the proposed information to its customer base.

The AER notes that JEN's proposals for enhanced customer communications relating to clause 9.1.2A of the Victoria Electricity Distribution Code and the customer charter were approved by the AER in its draft decision and updated in this final decision.

Regarding JEN's proposed newspaper advertising expenditure, AER notes that historically the Victorian DNSPs have been provided opex under the activity area of advertising and marketing. Amongst other things, this has been to communicate with customers on distribution matters including:

- providing notice of planned interruptions
- educating the public on network-related electricity safety
- activities arising from the DNSPs' reliability and quality of supply obligations.[251]

Therefore in relation to the actual opex incurred in the 2006–10 regulatory period, with exception of the requirements of clauses 9.1.2, 9.1.2A and 9.1.3 of the Victoria Electricity Distribution Code which are already accounted for elsewhere, the AER considers that the compliance costs of advertising and marketing are already included in JEN's base opex.

On this basis the AER is satisfied that the allowances approved in the AER's draft decision for JEN's and United Energy's enhanced customer communications and customer charter step changes reasonably reflect the efficient marketing costs of a prudent DNSP to comply with its regulatory obligations and operating environment in the forthcoming regulatory control period.[252]

AER conclusion

For the reasons discussed above, and as a result of the AER's consideration of JEN's and United Energy's revised regulatory proposals and other supporting information, the AER is not satisfied that JEN's and United Energy's proposed marketing communications costs are consistent with a total forecast opex that reasonably reflects the opex criteria.[253] The AER considers that the DNSPs have sufficient opex in their base year expenditure to undertake marketing activities. In coming to this view the AER has had regard to the opex factors.[254]

L.5.7 Advanced metering infrastructure related step changes

Victorian DNSPs proposed two step changes directly related to the new advanced metering infrastructure (AMI):

- data analysis and testing

[251] ESCV, *Electricity industry guideline No. 3: Regulatory information requirements issue No. 6*, December 2006, pp. 46–47.
[252] Clause 6.5.6(c)(1), 6.5.6(c)(2) and 6.5.6(a)(2) of the NER.
[253] Clauses 6.5.6(c)(1) and 6.5.6(c)(2) of the NER.
[254] Specifically opex factors (1), (3), (4) and (5).

- steady-state voltage violations.

L.5.7.1 Data analysis and testing

AER draft decision

The AER did not accept step changes for AMI data analysis and testing (referred to by United Energy as leveraging AMI technology to improve network operational management) on the basis that the DNSPs were unable to adequately demonstrate how the step changes reflect the efficient cost of achieving the opex objectives.[255]

Victorian DNSP revised regulatory proposals

JEN and United Energy both disagreed with the AER's draft decision on AMI data analysis and testing expenditure and resubmitted their initial proposals.

JEN acknowledged this step change is not required for successful delivery of the AMI program but stated that it is linked to a change in its operating environment, falls within criterion (e) of the Wilson Cook criteria as applied in the NSW Determination, and reasonably reflects the efficient costs of achieving the opex objectives, particularly (1), (3) and (4).[256] JEN identified outputs that the proposed expenditure will generate (discussed below), and provided a cost-benefit analysis[257] in support of its proposal.[258] JEN submitted that the drivers for this step change are:[259]

- to propose solutions to JEN's steady state voltage violations
- to pursue potential future benefits from the AMI data which might improve capex and opex efficiency.

JEN proposed $0.8 million ($2010) for this step change.[260]

United Energy submitted that this step change is required in order to maximise the benefits of the AMI program, and the proposed activities are not included in schedule 2.1 of the order in council (OIC) so have therefore not been funded by the metering charges.[261] United Energy noted that the benefits cannot be calculated because they are not yet known and may be in the form of customer benefits that are not cost savings to United Energy.[262] Such benefits include the ability to achieve faster restoration times following faults, increased capability to manage the network more dynamically and the ability to implement different engineering solutions based on AMI data.[263] United Energy proposed $1.4 million ($2010) for this step change.[264]

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255 AER, *Draft decision*, Appendix L, pp. 203–206.
256 JEN, *Revised regulatory proposal*, Appendix 7.2, pp. 32–33.
257 JEN, Response to information requested on 20 September 2010, 21 September 2010.
258 JEN, *Revised regulatory proposal*, Appendix 7.2, pp. 32–33.
259 ibid.
260 ibid.
261 United Energy, Revised regulatory proposal, p. 90.
262 ibid.
263 ibid.
264 ibid.

Submissions

VECCI expressed concern that smart metering costs imposed on small business should not exceed the benefits, and that it has not been able to identify network savings or benefits commensurate with the increase in metering charges previously approved.[265]

Issues and AER considerations

JEN stated that its proposed step change for AMI data analysis and testing is effectively for a senior engineer to analyse AMI data.[266] Outputs from this analysis identified by JEN included:[267]

- facilitating the development of software systems to assist in the process that extracts the data provided by AMI, performs data mining and analyses data to derive useful information from the vast amount of AMI data available;
- coordinating requirements from various subject matter experts across the business;
- researching and presenting business proposals;
- identifying voltage excursions outside of EDC limits and overloaded distribution transformers from AMI data and worsening trends by performing statistical data analysis, trending and clustering;
- optimally planning and initiating projects to correct identified issues; and
- conducting trials of other functions in AMI meters to deliver better customer service.

United Energy also stated that its step change is for one FTE staff to gather, analyse and transform AMI information.[268]

The AER has examined JEN's business case for this proposed step change.[269] Based on JEN's business case and the further information provided by JEN and United Energy demonstrating outputs that could arise from this proposed step change, the AER is satisfied that a prudent operator may wish to undertake such activities.

In response to United Energy's comment that no funding has been provided for data analysis and testing, the AER has reviewed JEN's and United Energy's joint 2009–11 AMI budget application.[270] JEN's and United Energy's budget application did not explicitly include expenditure for AMI data analysis and testing.[271] It follows that JEN and United Energy have not yet been funded for this step change.

265 VECCI, Submission, 26 August 2010, pp. 8–10.
266 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 32–33.
267 ibid.
268 United Energy, Response to information requested on 22 January 2010, 3 February 2010.
269 JEN, 2011/12 business case–AMI opex step change, confidential, June 2010.
270 JEN, United Energy, AMI Budget Application 2009–11—Substantiation of Base Costs to Provide Regulated services—Report prepared by Alinta Asset Management Pty Ltd for Jemena Electricity Networks and United Energy Distribution, 26 February 2009.
271 JEN, United Energy, *AMI Budget Application 2009–11, Chapter 5.*

The AER considers that the AMI rollout will likely generate a significant amount of information that JEN and United Energy have not encountered before which has value and could generate business efficiencies, which are difficult to identify and calculate at this time.[272] For example, JEN has identified that this data analysis and testing could lead to increased voltage violation detection. This will allow JEN to rectify voltage variation, which will reduce the early failure of light globes of JEN's customers. While the value of this benefit is difficult to calculate at this time, and is dependent on the success of the voltage violation detection, the AER considers that undertaking the data analysis and testing is an efficient business decision.

The AER is therefore satisfied of the need for the expenditure proposed by JEN and United Energy, and considers it forms part of a total opex forecast that reasonably reflects the opex criteria, in particular costs that a prudent operator in the circumstances of JEN and United Energy would require to achieve the opex objectives.[273]

In response to VECCI's submission the AER will ensure that efficiencies generated from this expenditure are shared with electricity consumers in future regulatory periods.

AER conclusion

For the reasons discussed above, the AER considers the expenditure proposed by JEN and United Energy is consistent with a total forecast opex that reasonably reflects the opex criteria.

Table L.42 AER final conclusion on AMI data analysis and testing expenditure ($'m, 2010)

	JEN	United Energy
	0.8	1.4

Source: AER analysis.

L.5.7.2 Steady-state voltage violations

AER draft decision

JEN and United Energy proposed a proactive approach to resolving steady-state voltage violations, corresponding to step changes of $0.6 million ($2010) and $1.0 million ($2010) respectively. The AER, however, did not accept that the approach they proposed in their initial regulatory proposals reasonably reflected the costs that a prudent operator in the circumstances of JEN or United Energy would require to achieve the opex objectives. In particular, the AER considered the lack of a change in regulatory obligations, as well as the DNSPs current approach to resolving steady-state violations.[274]

The AER also did not accept SP AusNet's claims that the introduction of AMI is expected to result in a 600 per cent increase in customer complaints relating to steady-

[272] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 32–33; United Energy, *Revised regulatory proposal*, p. 90.
[273] Particularly objectives (1), (3) and (4). NER, clauses. 6.5.6(c)(2) and 6.5.6(a).
[274] AER, *Draft decision*, Appendix L, pp. 204–205.

state voltage violations. This amounted to a $5.4 million ($2010) step change over the forthcoming regulatory control period. Primarily, the AER noted the lack of substantiation of these claims by SP AusNet.[275]

CitiPower and Powercor did not propose this step change.

Victorian DNSP revised regulatory proposals

JEN's revised regulatory proposal acknowledged that the relevant provisions of the *Electricity Distribution Code* (EDC) have not changed.[276] However, JEN disagreed with the AER's draft decision, noting that:

> … as a result of the better information available to JEN from the roll-out of AMI, JEN has a better understanding of the number and location of customers with steady state voltage levels exceeding the EDC requirement. The EDC requires JEN to use 'best endeavours' to minimise the frequency of voltage violations for periods of less than one minute. To the extent that JEN has better information about the number and location of customers with steady state voltage levels exceeding the EDC requirements, JEN's obligations under the EDC have in effect increased.[277]

Similarly, United Energy stated that:

> AMI meters will now provide UED with empirical evidence of voltage violations. With the receipt of this information, UED can no longer take a reactive approach and must now be proactive and address the voltage variations as they become known. To do otherwise would be a potential breach of its licence.[278]

SP AusNet also disagreed with the AER's draft decision. SP AusNet considered that the basis for the AER's rejection of its initial regulatory proposal was due to a lack of detailed quantitative data supporting SP AusNet's expectations.[279] Additionally, SP AusNet reiterated that as AMI will provide a level of transparency never experienced before it is reasonable to assume that there will be a higher incidence of customers complaining about their quality of supply.[280] SP AusNet also submitted that the proposed step change was consistent with section 7A(2)(a) of the NEL.[281]

Submissions

The AER received a submission from VCOSS on AMI related expenditure. VCOSS noted, in relation to SP AusNet's claim that quality of supply queries would increase by 600 per cent with the introduction of AMI, that:

> [i]t is not clear how consumers may actually receive notification of quality of supply issues in order to generate this call centre activity. Neither the current Energy Retail Code nor the Distribution Code require this information to be provided to consumers on their bills or in other notices and the ESC's draft determination on its regulatory review of smart meters

[275] AER, *Draft decision*, Appendix L, pp. 204–205.
[276] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 36–37.
[277] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 36–37.
[278] United Energy, *Revised regulatory proposal*, p. 93.
[279] SP AusNet, *Revised regulatory proposal*, p. 234.
[280] SP AusNet, *Revised regulatory proposal*, p. 235.
[281] SP AusNet, *Revised regulatory proposal*, p. 235.

> did not propose any additional requirements in this area. VCOSS strongly supports the AER's initial decision.[282]

Consultant review

Nuttall Consulting noted that it was reasonable to expect that a percentage of customers may currently be experiencing voltages outside of the EDC requirements and are not aware of this fact.[283] Nuttall Consulting also noted that the implementation of AMI is likely to identify these customers more quickly than current processes.[284] Accordingly, Nuttall Consulting considered that:

> [o]nce the AMI meter information regarding voltages [outside of the EDC requirements] is received by the DNSP, Nuttall Consulting understands that the DNSP is required to act to rectify the problem. To not act would be contrary to the code requirements.[285]

In the absence of AMI, Nuttall Consulting added that the identification of voltages that are outside of EDC requirements is difficult. In particular, Nuttall Consulting noted that current processes to test voltage levels typically involved a customer contacting the DNSP, followed by the installation of temporary metering at the customer's premises (and possibly in adjacent locations).[286]

In regard to SP AusNet's revised regulatory proposal, Nuttall Consulting agreed that the AMI rollout will bring forward the identification of voltages outside of Code requirements. Nuttall Consulting, however, considered that the AMI rollout will not cause new voltage problems. Nuttall Consulting stated that:

> … any allowance for costs in this category should only exist for the period of the AMI roll out. After the rollout, the advent of new voltage problems would be expected to continue at current levels.[287]

Further, Nuttall Consulting noted that the timing of SP AusNet's opex was not explained in SP AusNet's proposal. Nuttall Consulting was, therefore, unable to determine why the opex amounts proposed by SP AusNet are phased as they are.[288] Specifically, Nuttall Consulting noted that the AMI rollout will be completed in 2013, and considered that the required additional opex will only be required until 2014.

Issues and AER considerations

In the draft decision, the AER distinguished between 'practicable' and 'literal' compliance with the EDC. Further, the AER considered that the Victorian DNSPs' approach to resolving steady-state voltage violations over the 2006–10 regulatory control period demonstrated a level of compliance consistent with a 'practicable' application of the EDC.[289]

The AER has reviewed JEN's and United Energy's revised regulatory proposals. The AER accepts that although the relevant provisions of the EDC have not changed, the

282 VCOSS, Submission, August 2010, p. 3.
283 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 272.
284 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 272.
285 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 272.
286 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 272.
287 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 272.
288 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 272.
289 AER, *Draft decision*, Appendix L, p. 205.

introduction of AMI has increased the ability of the Victorian DNSPs to comply with provisions of the EDC relating to steady-stage voltage levels. In particular, the AER accepts JEN's statement that to the extent it has better information about the number and location of customers with steady state voltage levels exceeding EDC requirements, JEN's obligations under the EDC have effectively increased.[290]

The AER, however, is not satisfied that the proposed opex for rectifying steady state voltage violations can form part of a total forecast opex that reasonably reflects the opex criteria, in particular that it reasonably reflects the efficient costs of maintaining the quality, reliability and security of supply of standard control services.[291]

In response to questions prior to the draft decision, JEN and United Energy identified the following assumptions regarding the build up of its steady state voltage rectification costs:[292]

- the average unit rate for investigating and resolving power quality issues, based on current budgeting, is [confidential] for JEN and [confidential] for United Energy
- the expected opex savings for steady-state voltage related investigations, due to the availability of AMI, is approximately $77 ($2010) per investigation, or [confidential]
- 35 per cent of JEN's customers, and between 20 and 25 per cent of United Energy's customers, are likely to have steady state voltages outside of EDC limits at some time during the forthcoming regulatory control period
- based on the number of customers experiencing steady state voltages outside of EDC limits, 35 per cent of JEN's and 25 per cent of United Energy's distribution substations will be required to be inspected
- the unit rate per distribution substation visit is [confidential]
- the unit rate per zone substation visit is [confidential].[293]

The AER also notes that both JEN's and United Energy's step change proposals forecast a constant rate of expenditure for resolving voltage variations, from 2013 onwards for JEN and 2012 onwards for United Energy. JEN and United Energy, however, acknowledged that a clustering technique will be adopted to identify solutions for groups of customers, instead of individuals.[294]

290 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 36–37.

291 Consistent with NER, cl. 6.5.6(c)(1) and 6.5.6(a)(3).

292 As the AER's draft decision rejected the proposed step change on the grounds that a change in regulatory obligations had not occurred, these costs were not assessed during the draft decision

293 JEN, Response to information request on 22 January 2010, 25 February 2010; United Energy, Response to information request on 22 January 2010, 16 February 2010.

294 JEN, Response to information request on 22 January 2010, 25 February 2010; United Energy, Response to information request on 22 January 2010, 16 February 2010.

The AER does not consider that JEN's or United Energy's assumptions justify a step change that can form part of a total forecast opex that reasonably reflects the opex criteria.[295] Specifically, the AER has identified the following issues:

- The unit rates for investigating and resolving power quality issues are based on budgeted forecasts, not actual data. The budgeted number of power quality investigations ([c-i-c]) is well above historical actual averages ([commercial in confidence, commercial in confidence]). The AER considers that this difference has not been substantiated.

- The historical records from which JEN has forecast the number of expected power quality investigations, span 15 years, back to February 1995. Critically, the distribution of this data across the period has not been discussed.

- The unit rates per substation visit have not been substantiated.

- The benefits from JEN's proposed clustering approach to resolving voltage violations do not appear to have been appropriately quantified. Specifically, the AER considers that a declining profile of steady state voltage violations would reasonably be expected, as opposed to the constant forecasts proposed by JEN and United Energy.

The AER considers that collectively, these issues raise significant concerns as to the robustness and validity of JEN's and United Energy's forecasts. The AER, however, considers these issues to be secondary to the expected opex savings from the introduction of AMI.

In particular, the AER considers that the expected opex savings associated with the introduction of AMI ($77 per investigation) appear to be underestimated. The AER considers that smart meters will significantly reduce the number of site visits required to investigate suspected power quality issues, and largely eliminate the need to install diagnostic equipment to monitor steady-state voltage variations. The AER considers that the avoided costs of not having to undertake these processes are likely to approximate the costs of installing and removing metering equipment.

As such, the AER notes that the unit costs for installing a meter, as approved by the AER in the Victorian advanced metering infrastructure review 2009–11, AMI budget and charges applications, are $80 ($2010) for JEN and $69 ($2010) for United Energy.[296] The AER, however, also recognises that unlike the installation of smart meters, current processes for investigating and rectifying steady state voltage violations require a secondary site visit to remove any diagnostic equipment. Further, the AER notes that the AMI installation costs reflect significant economies of scale, in that site visits will install several meters throughout an area at the same time. Hence, call-out costs are spread across a large number of customers.

For these reasons the AER considers that the costs of investigating and rectifying steady state voltage violations are likely to be considerably higher than the

295 Specifically, NER, cl. 6.5.6(c)(1) and 6.5.6(a)(2).

296 AER, *Victorian advanced metering infrastructure review 2009–11, AMI budget and charges applications*, October 2009.

$77 ($2010) forecast by JEN and United Energy. In particular, the AER considers that a reasonable lower bound for the expected costs of investigating and rectifying steady state voltage violations is twice the approved unit costs for installing a smart meter.[297] That is, $159 ($2010) and $139 ($2010) for JEN and United Energy respectively.

The AER also notes that Futura Consulting, in a report commissioned by the Department of Primary Industries, stated that the introduction of AMI is more likely to halve the current unit rate for investigating and resolving power quality issues. Specifically, Futura Consulting stated:

> This [AMI] will provide DBs with much more information on quality of supply at each individual customer's premise. Hence, when customers raise a complaint about quality of supply, the DB can respond more quickly. With real time data, the question as to whether it is a real quality of supply issue or some other factor can quickly be resolved. If it is real issue, the data on neighbouring customers and LV network areas can be analysed to identify root causes quickly. Based on analysis of the tasks involved in investigating quality of supply complaints, the cost of investigating quality of supply complaints could be reduced by about 50 per cent.[298]

Based on the forecasts proposed by JEN and United Energy, the Futura Consulting estimate equates to avoided unit costs associated with the introduction of AMI to monitor steady state voltage violations of approximately [confidential] and [confidential] respectively. The AER considers that these estimates represent an upper bound for the expected costs of investigating and rectifying steady state voltage violations.

The AER, therefore, considers that JEN and United Energy have not factored into their opex forecasts additional avoided costs of $0.1 million ($2010) and $0.1 million ($2010) respectively over the forthcoming regulatory control period. These values represent the midpoint between the lower bound estimate (based on twice the installation costs of smart meters), and the upper bound estimate (based on Futura Consulting's estimate of 50 per cent of the average unit rate for investigating and resolving power quality issues). The AER has then subtracted the expected AMI savings already factored into JEN's and United Energy's forecasts, and multiplied the resulting values by the budgeted volume of power quality investigations related to steady state voltage violations.

Accordingly, the AER has adjusted JEN's and United Energy's proposed step change for resolving steady state voltage variations downwards, to $0.5 million ($2010) and $0.9 million ($2010) respectively over the forthcoming regulatory control period.[299] The AER considers these are the minimum changes necessary to provide opex

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297 This reflects the current need to undertake two site visits to investigate steady-state voltage violations. That is, one visit to install the diagnostic equipment, followed by a subsequent visit to remove the diagnostic equipment.

298 Futura Consulting, *Advanced Metering Infrastructure program – benefits realisation roadmap*, Final report, December 2009, p. 47.

299 The AER notes that the proposed step change reflects a greater volume of steady state violations that are currently rectified. The AER considers, however, that as more steady state voltage violations are identified and resolved by the DNSPs, the actual number of steady state voltage violations across the network will decline. The AER acknowledges that a backlog of violations are likely to persist in the 2011–15 regulatory control period, though considers that the equilibrium level of steady state voltage violations will be lower for future regulatory control periods.

forecasts for rectifying steady state voltage violations that are consistent with a total forecast opex that reasonably reflects the costs that a prudent operator in the circumstances of JEN and United Energy would require to comply with the EDC.

In regard to SP AusNet, the AER does not consider that the proposed costs for resolving quality of supply complaints are consistent with a total forecast opex that reasonably reflects the opex criteria, in particular the costs that a prudent operator in the circumstances of SP AusNet would require to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.[300]

Specifically, the AER does not consider that it is reasonable to expect that SP AusNet, as a prudent operator, will incur increased call centre activity due to increased complaints regarding quality of supply. As stated in the draft decision, the AER considers that customers typically only enquire about their power quality when the voltages delivered are well outside EDC limits.[301] Further, as noted by SP AusNet, current service level requirement specifications for retailers and customers do not include the provision of voltage quality data.[302]

The AER, therefore, is not satisfied that SP AusNet has sufficiently demonstrated that the introduction of AMI will result in a change to the external environment in the context of systematically increasing customer complaints. The AER notes that this view was strongly supported by VCOSS, in their submission in response to SP AusNet's revised regulatory proposal.[303]

The AER, however, accepts that like JEN and United Energy, to the extent that AMI provides better information about the number and location of customers with steady state voltage levels exceeding EDC requirements, SP AusNet's obligations under the EDC have effectively increased. That said, the AER does not consider the costs proposed by SP AusNet are consistent with a total forecast opex that reasonably reflects the opex criteria.[304]

In particular, the AER notes that SP AusNet's proposal is significantly greater than both JEN's and United Energy's forecasts on a per customer basis. Further, the AER considers that neither the average unit costs, nor the percentage of customers experiencing steady state voltage levels exceeding EDC requirements, are likely to vary markedly between the Victorian DNSPs.

Consequently, the AER has adjusted SP AusNet's opex forecast downwards by $4.6 million ($2010) over the forthcoming regulatory control period. The AER has calculated this adjustment as the average unit cost of JEN's and United Energy's approved step change for resolving steady state voltage violations, adjusted to reflect the difference in customer numbers between the DNSPs.[305] Further, the AER considers that the commencement of SP AusNet's step change is likely to be consistent with the implementation of JEN's proactive mitigation programme. That is,

300 Consistent with the NER, cl. 6.5.6(c)(1) and 6.5.6(a)(1).
301 AER, *Draft decision*, p. 205.
302 SP AusNet, Response to information requested on 22 January 2010, 5 February 2010.
303 VCOSS, Submission, August 2010, p. 3.
304 Consistent with the NER, cl. 6.5.6(c)(1).
305 JEN, Response to information request on 22 January 2010, 25 February 2010.

the AER has approved additional expenditure for SP AusNet's from 2012 onwards, allowing for a time lag between the introduction of AMI and the associated systems and training required to implement the mitigation programme, as noted by JEN. This reduces SP AusNet's proposed step change for resolving steady state voltage variations to $1.1 million ($2010) over the forthcoming regulatory control period.

The AER considers that this adjustment reflects the minimum change necessary to provide opex forecasts for rectifying steady state voltage violations that are consistent with a total forecast opex that reasonably reflects the efficient costs that a prudent operator in the circumstances of SP AusNet would require to comply with the EDC.[306]

AER conclusion

For the reasons discussed above, the AER considers its estimates set out in table L.43 are part of a total forecast opex that reasonably reflects the opex criteria.

Table L.43 AER final conclusion on steady-state voltage violations expenditure ($'m, 2010)

JEN	SP AusNet	United Energy
0.5	1.1	0.9

Source: AER analysis.

L.5.8 Regulatory submission costs

L.5.8.1 AER draft decision

The AER considered that where significant increases exist in a DNSP's base year opex, due to regulatory submission costs, the appropriate treatment should be to remove these costs from the base year and provide them as a step change for the forthcoming regulatory control period. Where the AER identified this in the Victorian DNSPs' regulatory proposals, it applied this approach.

In determining the Victorian DNSPs' regulatory submission costs for the forthcoming regulatory control period, the AER took their respective 2006–10 regulatory period regulatory submission costs and adjusted these forward.[307]

The AER noted that SP AusNet provided evidence that its regulatory costs had not materially fluctuated over the 2006-10 regulatory period and that it would not experience a significant increase in expenditure in its base year. The AER therefore considered that SP AusNet demonstrated that its regulatory costs occur evenly over the regulatory control period and that an adjustment to SP AusNet's base and a step change allowance was not required.

L.5.8.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs generally agreed with the draft decision.[308] The only contention was provided by JEN who proposed an increase in its step change from $3.5 million

306 Consistent with the NER, cl. 6.5.6(c)(1), 6.5.6(c)(2) and cl. 6.5.6(a)(2).
307 NER, clause 6.5.6(e)(5).

in its initial regulatory proposal to $7.5 million in its revised regulatory proposal.[309] JEN stated that it had used the same approach and methodology in determining its revised forecast, however the increase was due to more accurate information being available than the initial proposal for this step change.

L.5.8.3 Issues and AER considerations

The AER notes that CitiPower, Powercor and United Energy agreed in their revised regulatory proposals with the AER's draft decision on the treatment of their regulatory submission costs and did not raise any further issues regarding this step change.[310]

With respect to the AER's draft decision and SP AusNet's evidence that its regulatory costs do not fluctuate over a regulatory control period, as discussed in section 6.7.3, the AER no longer considers this appropriate in relation to the treatment of SPI Management Services' (SPIMS) management labour regulatory submission cost adjustments.

SPIMS costs are allocated between different business segments—regulated electricity distribution, regulated gas distribution, AMI, unregulated distribution, regulated transmission, unregulated transmission, and non-SP AusNet—based on management survey of 'effort'. As the survey is completed regularly (currently every three months), the percentage allocations between segments also change regularly.

As noted in section 6.7.3, the AER accepts that in the lead up to the submission of a regulatory proposal, SP AusNet's management would be expected to exert more 'effort' on the electricity distribution business and so more electricity distribution costs would be expected during this time. However, as these costs would be non-recurrent in nature, the 'average' adjustment in the draft decision excluded these non-recurrent costs from the base opex forecast. Consistent with its treatment of regulatory submission costs for the other DNSPs, the SPIMS management labour regulatory submission cost adjustments which are removed from the base opex should be added back as an opex step change, but only in the year's they are expected to be incurred.

Therefore, consistent with section 6.7.3, the SPIMS management labour regulatory submission costs adjustment has been removed from SP AusNet's base opex and have been provided for here as an opex step change for years 2014 and 2015.

With respect to JEN's revised regulatory proposal, the AER requested JEN to provide further information detailing the reasons for the significant increases in costs in their proposal for this step change. JEN's response to this request outlined that the increase in 2009 and subsequently its proposal for 2014 costs were due to a delay in accounting treatment of costs that had not been acknowledged or processed by the

308 CitiPower, *Revised regulatory proposal*, pp. 177, 210–214; Powercor, *Revised regulatory proposal*, pp. 166-167, 200–202; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 70–71; United Energy, *Revised regulatory proposal*, p. 95.

309 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 70–71.

310 CitiPower, *Revised regulatory proposal*, p. 177; Powercor, *Revised regulatory proposal*, p. 167; United Energy, *Revised regulatory proposal*, p. 95.

time its initial regulatory proposal was submitted.[311] JEN updated its proposed 2014 costs in its revised regulatory proposal to reflect this accounting treatment.

JEN further noted that its 2010 costs and its proposed 2015 costs were due to an underestimation of the volume of work involved in the preparation of its regulatory submission.[312] JEN also noted that additional resources and expert assistance was primarily required for responding to the AER's draft decision, responding to an additional regulatory information notice and additional dealings with the AER.

The AER notes that all of the Victorian DNSPs had the same requirements and only JEN has recognised significant increased costs in 2010 which are reflected in their revised proposal for 2015. The AER observes that unlike JEN the other Victorian DNSPs' regulatory costs profiles demonstrated a lower or equal cost in the last year of the regulatory period compared to the penultimate year. While JEN's increase in 2009 costs and proposal for 2014 costs are comparable to the other Victorian DNSPs, its 2015 proposed costs (based on 2010 estimated costs) deviate substantially and are significantly higher than the other DNSPs. The AER notes that JEN's proposal for 2015 costs are over double that of any other Victorian DNSP for the same year.

While the AER acknowledges that not all the Victorian DNSP's circumstances are the same and therefore not all incur the same costs, the AER considers that JEN's proposed costs for 2015 are excessively high. The AER's considerations are based on the cost profiles of the other Victorian DNSPs as well as the consideration that the level of costs JEN incurred in 2010 (such as costs incurred due to an additional regulatory information notice) is not anticipated to occur in 2015 given the expected refinement in the AER's 2016–20 distribution determination process for Victoria.

Based on this the AER considers that the efficient and prudent costs that a DNSP would incur in the forthcoming regulatory control period for regulatory submission costs would be comparable to the costs incurred by the other Victorian DNSPs. The AER considers the comparable costs of the other Victorian DNSPs regulatory submission costs provide a basis of reference that would represent the benchmark opex that would be incurred by an efficient Victorian DNSP in the forthcoming regulatory control period.

Therefore, the AER accepts JEN's proposed costs for 2014 (based on 2009 actual costs) as these are comparable to the other Victorian DNSPs. However, the AER does not accept JEN's proposed costs for 2015 (based on 2010 estimated costs) as these are not comparable to the other Victorian DNSPs.

In relation to the benchmark opex that JEN would incur for 2015 regulatory submission costs, the AER has substituted JEN's initial proposal for the 2015 costs which is comparable with the proposed 2015 costs for the other Victorian DNSPs. The AER notes that its substitute costs for 2015 (the initial regulatory proposal costs for 2015) are mid-range costs of the Victorian DNSPs for this particular year. Combined with JEN's revised costs for 2014, JEN's total regulatory submission costs are the highest of all Victorian DNSPs in the forthcoming regulatory control period. The AER considers that these are reasonable estimates for the efficient costs that JEN

311 JEN, Response to information requested on 2 September 2010, 10 September 2010.
312 JEN, Response to information requested on 2 September 2010, 10 September 2010.

would incur for regulatory submission costs over the forthcoming regulatory control period.

Further, the AER considers that in JEN's circumstances additional costs have been incurred in 2010 over that in its estimates. While the AER has not made an allowance for these additional costs in the forthcoming regulatory control period JEN as the AER notes that any additional one off costs (actual costs above estimated costs) incurred by JEN in 2010 will be shared between JEN and its customers under the AER's efficiency benefit sharing scheme (EBSS). Therefore, no adjustments for these increases in costs are required in the forthcoming regulatory control period.

L.5.8.4 AER conclusion

For the reasons above and having regard to a benchmark firm and the actual costs incurred relating to the Victorian DNSPs regulatory submission costs in the 2006–10 regulatory period as part factors 4 and 5 of the opex factors, the AER considers:

- that CitiPower's, Powercor's and United Energy's proposals are consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria
- that JEN's proposal is not consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria and accordingly, the AER has substituted the 2015 costs in the revised proposal with JEN's initial regulatory proposal costs for 2015
- the removal of SPIMS' costs from SP AusNet's base year should be provided for as a step change which the AER considers is consistent with a total forecast opex that reasonably reflects the opex criteria.

Table L.44 AER conclusion on regulatory submission costs ($'m, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
1.7	4.0	4.4	3.0	2.2

Source: CitiPower, *Revised regulatory proposal*, p. 211; Powercor, *Revised regulatory proposal*, p. 200; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 70–71; United Energy, *Revised regulatory proposal*, p. 95, AER analysis.

L.5.9 SP AusNet's IT opex

L.5.9.1 AER draft decision

In its initial regulatory proposal SP AusNet stated that the planned replacement of existing IT systems during the forthcoming regulatory control period (as part of its capex program) would have a consequential effect on IT opex. SP AusNet identified that additional operating costs will arise in relation to ongoing support, training users of the new systems, and administering and licensing new IT systems.[313] The AER inadvertently overlooked this proposal in the draft decision.

313 SP AusNet, *Regulatory proposal*, November 2009, pp. 173, 213–214.

L.5.9.2 Victorian DNSP revised proposals

In its revised proposal, SP AusNet resubmitted its IT opex proposal noting:[314]

> As SP AusNet does not accept the AER's proposed reduction in its IT capital expenditure program, SP AusNet does not accept the proposed reduction in its opex costs associated with this increased IT capex program.

As part of its initial proposal, SP AusNet developed an IT strategy in support of its proposed IT expenditure.[315] In the IT strategy, SP AusNet forecast total IT opex step changes at approximately $37 million for the forthcoming regulatory control period.[316] SP AusNet categorised the step changes in forecast IT operating expenditure into the following categories:[317]

1. AMI Related—In February 2009, SP AusNet submitted an updated AMI budget application to the AER. SP AusNet forecasts that IT expenditures necessary to maintain the IT systems and infrastructure to deliver AMI and allocation to the distribution electricity network will total $14.6 million.

2. Program Related—Through the delivery of the IT Program of work over the forthcoming regulatory control period, SP AusNet forecasts an increase in operating expenditure of $11.9 million.

3. Project Delivery—Through the delivery of the IT Program of work over the forthcoming regulatory control period, SP AusNet will incur project operating expenses for activities such as training, tendering and business case development. SP AusNet forecasts these expenditures to be $5.2 million.

4. Service Changes—Service changes forecast for 2010 are anticipated to be recurring and therefore, are forecast to be $5.2 million over the forthcoming regulatory control period.

SP AusNet noted that in forecasting operating expenditure for the forthcoming regulatory control period, for each project it has:[318]

- engaged business units to understand the anticipated efficiency benefits and the material impact those benefits have on forecast operating expenditures

- determined whether the benefits are recurring or once off and apply those benefits to the 2009 base year

- determined whether the project is materially adding IT systems and infrastructure that did not exist in the 2009 base year and for those new IT systems and infrastructure forecast required labour and software and hardware maintenance to support and maintain those IT assets

- applied these costs from the anticipated commission date of the project.

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314 SP AusNet, *Revised regulatory proposal*, p. 191.
315 SP AusNet, *Regulatory proposal,* Appendix F, November 2009.
316 ibid., pp. 105–106.
317 ibid., p. 106.
318 SP AusNet, *Revised regulatory proposal*, p. 191.

L.5.9.3 Consultant review

The AER engaged Nuttall Consulting to assist the AER with its assessment of these step changes. Nuttall Consulting considered each of the four IT opex step changes and noted that the outcomes of the efficiency assessments mentioned above are not provided in any qualitative fashion that would enable them to be identified or assessed.[319]

L.5.9.4 AER issues and considerations

The AER notes that SP AusNet's IT capex program has been accepted by the AER in its entirety, as discussed in chapter 8 and appendix P. The AER considers the increase in capital works proposed is prima facie justification for an increase in supporting opex.

AMI related

As noted above, SP AusNet has included $14.6 million in opex step changes for AMI systems and infrastructure related IT expenditure. In April 2009, SP AusNet engaged Deloitte to review its AMI IT budget application. Deloitte adopted a 'fact based approach' which, according to SP AusNet's IT strategy, resulted in an allocation of AMI IT expenditure across SP AusNet's businesses as follows:[320]

Table L.45 SP AusNet AMI IT capital and operating expenditure allocation (per cent)

AMI Project	Elec	Gas	Trans	AMI	Total
Meter Data Management	0	0	0	100	100
Network Billing Upgrade	70	30	0	0	100
EAI Upgrade	49	21	30	0	100
EAI Integration	3	1	2	94	100
IT Infrastructure	28	12	17	43	100
Customer Information System	60	26	0	15	100
PowerOn Separation	50	0	0	50	100
Data Warehouse	22	0	0	78	100
Document Archive	60	26	0	15	100

Source: SP AusNet, *Regulatory proposal*, Appendix F, November 2009, p. 47.

SP AusNet's IT strategy states that SP AusNet has 'recognised the opportunity to efficiently deliver the AMI program by leveraging IT systems and infrastructure'.[321] The IT strategy also notes that the AER accepted the above allocation of AMI IT capital and operating expenditure across SP AusNet's businesses in the final

319 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 249.
320 SP AusNet, *Regulatory proposal*, Appendix F, November 2009, p. 47.
321 SP AusNet, *Regulatory proposal*, Appendix F, November 2009, p. 46.

determination of the Victorian Advanced Metering Infrastructure review in October 2009.[322]

In response to a request for further information, SP AusNet noted that the costs allocated to the electricity distribution businesses are business as usual costs which are covered by SP AusNet's total IT proposal, and not the AMI Order in Council (OIC).[323] SP AusNet considered that business as usual costs need to be recovered separately through price resets.[324] It follows that the $14.6 million for this proposal reflects the allocation in the 'Elec' column in Table L.45, and the amount already approved in the AMI Cost Recovery Determination reflects the allocation in the 'AMI' column.

The AER acknowledges that the introduction of AMI is a major change for the Victorian DNSPs, resulting in the need to implement new IT systems to cater for the new technology. The AER considers that SP AusNet's allocation of IT expenditure over its businesses is more efficient than the alternative of creating an isolated IT system solely for AMI. The AER considers that the AMI infrastructure has the potential for benefits and efficiencies beyond metering that are currently incalculable. The AER will ensure that these future benefits are shared with electricity customers through the EBSS and the STPIS.

The AER acknowledges that although SP AusNet did not adequately explain the quantum of the proposed expenditure, the new IT systems approved as part of the total capex program will require maintenance. Accordingly, the AER accepts the need for the expenditure, and considers that there is nothing to suggest that SP AusNet's proposal for approximately 10 per cent of the non-network—IT capex program is not a prudent figure.

Accordingly the AER is satisfied that the proposed step change will form part of a total forecast opex that reasonably reflects the efficient costs that a prudent operator in SP AusNet's circumstances would require to achieve the opex objectives.[325]

Program related

SP AusNet has forecast an increase in program related opex of $11.9 million over the forthcoming regulatory control period. SP AusNet's IT strategy states that the forecasts for these programs are detailed in section 6 of the IT strategy.[326] However, upon initial examination of the programs detailed in section 6 of the IT strategy, Nuttall Consulting identified an inconsistency between the $11.9 million total program related opex figure, and the sum of the opex for each program ($3.57 million). [327]

322 ibid.
323 SP AusNet, Response to information requested on 7 October 2010, 13 October 2010.
324 ibid.
325 NER, clauses 6.5.6(c)(1) and (2).
326 SP AusNet, *Regulatory proposal*, Appendix F, November 2009, p. 106.
327 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, pp. 251–252.

In response to a request for further information, SP AusNet noted that the breakdown of costs in section 6 of the IT strategy cannot be reconciled with the total figure.[328] SP AusNet confirmed the following is a breakdown of its program related IT opex:

Table L.46 SP AusNet program related IT opex step changes ($'000, 2009)

Program	2011	2012	2013	2014	2015	Total
End user computing	–	–	227.3	231.5	277.8	736.6
Application services	–	–	10.5	260.7	582.0	853.2
Managed services	1781.0	1576.8	1631.0	2764.1	2234.6	9987.5
Project and advisory	–	–	27.3	31.5	37.8	96.6
Real time systems	–	–	27.3	31.5	37.8	96.6
IT service management	–	–	27.3	31.5	37.8	96.6
Total	**1781.0**	**1576.8**	**1950.7**	**3350.8**	**3207.8**	**11 867.1**

Source: SP AusNet, Response to information requested on 7 October 2010, 13 October 2010.

The AER notes that SP AusNet's response to the AER's information request was received after Nuttall Consulting's report had been finalised, so the AER's consideration of Nuttall Consulting's recommendations has taken this into account.

Nuttall Consulting considered, based on the information available at the time, that in some cases, it appears the benefits of the program related expenditure have been taken into account in determining the opex forecast. However, in other cases, it is not clear whether or not the benefits have been factored into the opex forecast amounts.[329]

Nuttall Consulting considered that upon review of the proposed expenditures, the descriptive information is relatively good, but the quantification of the benefit and cost breakdowns are not provided in a manner that allows the timing, efficiency or prudency of the projects to be assessed.[330] The AER considers that SP AusNet's response to the AER's information request has clarified the issues of quantification and timing.

Nuttall Consulting was also able to identify linkages between SP AusNet's 2006–2010 EDPR submission and current revised proposal, and considered this provided some degree of validation for the proposed projects.[331] On this basis, Nuttall Consulting recommended that the $3.57 million identified be accepted, noting that information supporting $11.9 million could not be located.[332]

328 SP AusNet, Response to information requested on 7 October 2010, 13 October 2010.

329 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, pp. 252–253.

330 ibid.

331 ibid.

332 ibid.

SP AusNet noted in its information request response that the bulk of program related IT opex is due to increases in managed services, which covers operating services costs (such as services provided by EBS to SP AusNet) and the support costs for replaced and new systems.[333] SP AusNet has not adequately justified the efficiency of this expenditure, but as noted above, the AER considers that the increase in SP AusNet's approved IT capital works required as a result of the introduction of AMI is a sufficient change in SP AusNet's operating environment to justify additional opex to support the IT capex programs. The AER also notes Nuttall Consulting's observation that linkages between SP AusNet's 2006–2010 EDPR submission and current revised proposal exist, which provides some validation for the expenditure.[334] The AER accepts the need for the expenditure, and considers that there is nothing to suggest that SP AusNet's proposal is not a prudent figure.

Accordingly the AER is satisfied that the proposed step change will form part of a total forecast opex that reasonably reflects the efficient costs that a prudent operator in SP AusNet's circumstances would require to achieve the opex objectives.[335]

Project delivery

SP AusNet's IT strategy contained forecast project delivery related IT opex totalling $5.2 million for the forthcoming regulatory control period.[336] The AER notes that further detail of this step change is provided in section 7.24 of SP AusNet's IT strategy, which states this expenditure comprises the following:[337]

- project delivery at 5 per cent of forecast capex for project related activities—$7.6 million
- manual data cleansing, which involves the elimination of duplicate, fragmented or redundant data and typically necessitates the need for targeted field capture of data pertaining to network assets—$1.5 million
- organisational change management, which is a process used when significant changes are implemented, that impact roles, responsibilities and cultural aspects of an organisation and is designed to ensure organisational change is implemented in an orderly, controlled and systematic way—$0.5 million
- IT service management, which is an integrated approach to enable an organisation to effectively and efficiently deliver managed IT services which meet business and customer requirements—$0.5 million.

The AER sought further information from SP AusNet after being unable to reconcile the total of the project delivery program ($5.2 million) with the sum of the individual components ($10.13 million).[338] SP AusNet stated that $10.13 million is the correct figure, but represents total project delivery opex. The step change amount is $4.06

333 SP AusNet, Response to information requested on 7 October 2010, 13 October 2010.
334 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 253.
335 NER, clauses 6.5.6(c)(1) and (2).
336 SP AusNet, *Regulatory proposal*, Appendix F, November 2009, p. 106.
337 ibid., p. 108.
338 As with program related IT opex, this information was received after Nuttall Consulting's report had been finalised.

million and the remainder is embedded in base year costs.[339] SP AusNet did not specify which components of project delivery opex are base year costs and which are step changes.

However, given the above descriptions, the AER considers it is reasonable to assume that manual data cleansing, operational change management and IT service management expenditure would already be included in SP AusNet's base opex because such expenditure should be general expenditure that recurs in each regulatory control period. The AER also considers that project delivery opex would be included in SP AusNet's base opex for the same reason, but accepts that with the increase in accepted proposed IT capex, there is likely to be an additional requirement for project delivery opex.

The AER notes that SP AusNet did not adequately justify the figure of 5 per cent of forecast capex for project related activities other than that it has been derived from historical program related operating expenditure and adjusted in recognition of efficiencies arising from economies of scale.[340] However, the AER notes that Nuttall Consulting considered it feasible that this percentage could be an overstatement or an understatement of the likely relationship, and accepted this position put forward by SP AusNet in the absence of information to determine either.[341] The AER considers that there is nothing to suggest that 5 per cent of forecast IT capex is not a prudent figure for this expenditure.

In any event, it follows from SP AusNet's response to the AER's request for further information that not all of the 5 per cent of forecast IT capex amount is a step change. SP AusNet notes that the $4.06 million amount for this step change represents the increased costs expected in relation to the more extensive IT capex program to be undertaken in the 2011–15 regulatory control period.[342]

As with the other IT step changes above, the AER considers the increase in SP AusNet's approved IT capital works required in the forthcoming regulatory control period as a result of the introduction of AMI is a sufficient change in SP AusNet's operating environment to justify this additional opex.

The AER is therefore satisfied that the project delivery step change will form part of a total forecast opex that reasonably reflects the efficient costs that a prudent operator in SP AusNet's circumstances would require to achieve the opex objectives.[343]

Service changes

SP AusNet has forecast three service changes commencing in 2010 and anticipated to be recurring, totalling $5.2 million for the forthcoming regulatory control period.[344] SP AusNet's IT strategy points to section 7.1 (of the IT strategy) for a more detailed

[339] SP AusNet, Response to information requested on 7 October 2010, 13 October 2010.
[340] SP AusNet, *Regulatory proposal*, Appendix F, November 2009, p. 106.
[341] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 254.
[342] SP AusNet, Response to information requested on 7 October 2010, 13 October 2010.
[343] NER, clauses. 6.5.6(c)(1) and (2).
[344] SP AusNet, *Regulatory proposal*, Appendix F, November 2009, p. 106.

description of the service changes. The extent of the additional detail provided in section 7.1 is as follows:[345]

> 2009 Service Changes—In 2009, SP AusNet requested several service changes that are forecast at $1.0M per annum recurring. These service changes included additional 24 x 7 support for the [Network Operations Centre], costs associated with material increase in Service Desk volumes and Maximo Service Requests.

The AER notes that Nuttall Consulting considered the three service changes identified by SP AusNet all appear to be linked to growth in the network and/or customer base.[346]

The AER agrees with Nuttall Consulting and notes that the increased costs associated with these service changes would normally be accounted for by the AER's scale escalation allowance. Scale escalation provides funding for the DNSPs for increased operating and maintenance expenditure arising from growth in their distribution networks by way of an adjustment to base opex. Scale escalation is assessed in appendix J of this final decision.

However, SP AusNet has not been provided with a scale escalation allowance for its operating expenditure, only for maintenance expenditure. The basis for this is SP AusNet's statement in its revised proposal that, due to perceived productivity savings, scale escalation need only be applied to opex in the event that SP AusNet's IT capex program is not accepted by the AER.[347]

Since SP AusNet's IT capex proposal has been accepted by the AER, SP AusNet will not receive a growth allowance for opex (including IT expenditure). The AER therefore considers that this step change should be allowed because it will form part of a total forecast opex that reasonably reflects the efficient costs of achieving the opex objectives as required by clause 6.5.6(c) of the NER. Accordingly, the AER has accepted this step change.

L.5.9.5 AER conclusion

For the reasons discussed above, the AER considers $37.4 million ($2010) as proposed by SP AusNet for IT systems is part of a total forecast opex that reasonably reflects the opex criteria, particularly the efficient costs required by a prudent DNSP in the circumstances of SP AusNet to achieve the opex objectives.[348]

L.5.10 Demand management step changes

L.5.10.1 AER draft decision

In its initial regulatory proposal United Energy proposed an increase in its DMIA allowance from $2 million to $10 million.[349] The AER therefore assessed United Energy's demand management proposal in the context of the demand

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345 ibid., p. 104

346 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October, pp. 255–256.

347 SP AusNet, *Revised regulatory proposal*, p. 196.

348 NER, cl. 6.5.6(c)(3).

349 United Energy, *Regulatory proposal*, pp. 236–238.

management incentive scheme. The AER did not accept United Energy's proposed increase in the DMIA in the draft decision.[350] In its revised proposal United Energy has clarified that the proposed $10 million in demand management initiatives was intended as step change opex and is in addition to the $2 million available through the DMIS.[351] This is discussed below.

The AER did not consider SP AusNet's proposed $10.8 million in demand management initiatives as a step change in the draft decision. This is also discussed below.

L.5.10.2 Victorian DNSP revised regulatory proposals

SP AusNet commented that the AER mischaracterised its proposed $10.84 million of demand management opex as a proposed increase in the DMIA.[352]

In its revised regulatory proposal SP AusNet did not change the demand management programs it proposed in its initial regulatory proposal because it considered that they were efficient, met the requirements of the NER and that the AER did not justify its rejection of the expenditure in the draft decision.[353] SP AusNet proposed the following demand management opex step changes for the forthcoming regulatory control period:

- Non-networks team ($3.80 million)—to establish a team to promote efficient non-network solutions. This expenditure includes formal training and development, and the establishment of data, systems and tools to facilitate non-network planning.

- Deferral of capex ($2.43 million)—SP AusNet identified potential capex savings from the deferral of projects enabled by non-network solutions, including a $7.4 million to upgrade the Benalla zone substation in 2011.

- Demand management programs ($3.29 million)—this includes hot water system timing, which would allow the deferral of $7.1 million ($2010) of capex, and a trial of direct load control of air-conditioning.

- Tariffs ($1.32 million)—includes costs of making system and process changes, such as customer notification systems and resources to maintain and update tariff tables, for the introduction of innovative tariffs (TOU and critical peak pricing). SP AusNet stated that these are in addition to the costs recovered under the AMI regulatory process, which include the cost of the AMI meter and the communication mechanism associated with that meter.[354]

United Energy stated that the AER misinterpreted its proposed demand management operating expenditure as a bid to increase the allowance under the DMIA to $10 million over the forthcoming regulatory control period.[355] United Energy

350 AER, *Draft decision*, p. 735.
351 United Energy, *Revised regulatory proposal*, pp. 307–321.
352 SP AusNet, *Revised regulatory proposal*, p. 269.
353 SP AusNet, *Revised regulatory proposal*, p. 263.
354 SP AusNet, *Revised regulatory proposal*, pp. 269–271; SP AusNet, *Regulatory proposal*, pp. 237–251.
355 United Energy, *Revised regulatory proposal*, p. 307.

expressed regret at the reference to the DMIS building block component in section 18.6.4 of its initial regulatory proposal. As a result the AER did not assess the proposed $10 million demand management initiatives under the opex provisions of the NER.[356]

United Energy expressed its commitment to explore and develop the following demand management initiatives:

- Use of AMI data for demand management ($1.0 million)—to develop an approach to efficiently and effectively gather data from the rollout of AMI and establish systems and protocols to make the data available across the business and to industry more broadly.

- Preparations for critical peak pricing ($0.5 million)—for the collection of data and to engage with industry and retailers in the development and implementation of critical peak pricing.

- RIT-D and demand participation engagement ($0.5 million)—to establish systems and data to support the new obligations under the RIT-D and demand side engagement strategy.

- Broad based demand management initiatives ($6.0 million)—under this initiative United Energy seeks to replicate schemes that have been put into practice in other jurisdictions and to work in conjunction with demand-side aggregators. United Energy stated that the proposed activities are a prudent and efficient approach to managing the network and are likely to lead to lower costs and improved service for customers.

- Demand management team ($2.0 million)—for the establishment of a team to promote demand management solutions within the business and to ensure that non-network proponents have access to appropriate information. This expenditure includes the costs of hiring and retaining an appropriate staff complement in the forthcoming regulatory control period.[357]

United Energy stated that costs and benefits of demand management initiatives cannot by their nature be readily forecast up to five years in advance. However, United Energy confirmed with Energy Response and Secure Energy that the programs envisaged by United Energy can deliver significant benefits. United Energy pointed to submissions received by the AER and anecdotal evidence that suggest that consumers are prepared to fund initiatives which produce external or ancillary benefits.[358]

356 United Energy, *Revised regulatory proposal*, p. 312.
357 United Energy, *Revised regulatory proposal*, pp. 313–314, 315–320. More information can be found in UED, *Regulatory proposal*, chapter 18.
358 United Energy, *Revised regulatory proposal*, pp. 318–320.

Table L.47 Proposed demand management step change ($'000, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet	2020	2200	2130	2220	2190	**10 760**
United Energy	700	1800	2500	2500	2500	**10 000**

Source: SP AusNet, *Revised regulatory proposal*, p. 266; United Energy, *Revised regulatory proposal*, p. 321.

L.5.10.3 Submissions

Energy Response expressed disappointment that the AER did not consider the Victorian DNSPs' proposed demand management and non-network related programs and stated that the Victorian DNSPs' proposals were too small to make a meaningful impact to their works program in the forthcoming regulatory control period.[359]

Energy Response commented that the DMIS is overly modest and that pilots and trials for non-network options that have been proposed above the DMIA should be supported through an opex allowance.[360]

The Total Environment Centre (TEC) stated that the draft decision failed to appropriately consider the extent to which non-network solutions should have been utilised to defer augmentations. The TEC recommended that the AER commission a report to investigate potential savings if the Victorian DNSPs properly implemented non-network solutions. The TEC also recommended that the AER require DNSPs to spend a certain percentage on non-network solutions (starting at 2% and eventually reaching around 10%).[361]

The TEC commented that the AER should support SP AusNet's efforts to articulate an approach to demand management including the non-network team, capex deferral initiatives and technology trials.[362]

CSIRO expressed disappointment that the draft decision did not mention SP AusNet's network storage demonstration project and encouraged the AER to consider this project.[363]

L.5.10.4 Consultant review

SP AusNet

Non-networks team

Nuttall Consulting noted that the status of the AEMC Review of National Framework for Electricity Distribution Network Planning and Expansion (upon which SP AusNet's program is partly based) and the proposed implementation dates were unclear. Nuttall Consulting recommended accepting the $3.80 million proposed to

[359] Energy Response, Submission, 17 August 2010, p. 1.
[360] Energy Response, Submission, 17 August 2010, p. 2.
[361] TEC, Submission, 24 August 2010, p. 2.
[362] TEC, Submission, 24 August 2010, p. 4–7.
[363] CSIRO, Submission, 19 August 2010.

establish a non-networks team if the AER is satisfied that it meets the requirements of clause 6.5.6(a)(2) of the NER.[364]

Deferral of capex

Nuttall Consulting commented that SP AusNet provided a reasonably robust analysis of the options and costs associated with the Benalla feeder augmentation, which showed likely benefits from the use of non-network solutions to defer capex. The analysis is less detailed for the other projects (summarised in table 8.1 of SP AusNet's initial regulatory proposal).[365]

Nuttall Consulting considered that SP AusNet provided reasonable evidence that the proposed expenditure is prudent and efficient and recommended that it be included in forecast allowances.[366]

DM programs

Nuttall Consulting stated that SP AusNet provided sufficient information regarding the hot water system load control program ($1.26 million) to consider the associated opex to be prudent and efficient and recommended that this be included in allowed expenditures.[367]

Nuttall Consulting considered that SP AusNet did not provide sufficient justification to suggest that the proposed opex for the direct load control of air conditioning ($2.03 million) is prudent and efficient. In particular, SP AusNet did not quantify the benefits or cost deferrals for the proposed works.[368]

Tariffs

Nuttall Consulting noted SP AusNet's estimates that by the end of 2013 the adoption of TOU tariffs would lead to a reduction in peak and shoulder energy and a slight increase in off peak usage relative to the business as usual (BAU) scenario. SP AusNet also estimated that critical peak demand pricing would lead to a saving in the peak summer demand of 90.22MVA.[369]

Nuttall Consulting noted that the summer peak demand reduction has been recognised in SP AusNet's demand forecasts. It is therefore reasonable that the program to implement the new DUOS tariffs is accepted.[370]

United Energy

Use of AMI data for demand management

[364] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 258.
[365] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 258.
[366] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 258–259.
[367] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 260–261.
[368] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 260–261.
[369] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 261–262.
[370] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 262.

United Energy's proposed expenditure for this program was based on its own assessment of costs and is supported by analysis undertaken in its Smart Grid, Smart City proposal and advice from Secure Energy and Secure Partners.[371]

Nuttall Consulting concurred with United Energy's position that the investment in AMI should be allowed to deliver intended benefits. However the expenditure proposed by United Energy for the use of AMI data for demand management provided no quantification of benefits. Nuttall Consulting was not satisfied that the proposed expenditure is either prudent or efficient.[372]

Critical peak pricing

In seeking to understand the possible benefits of the proposed step change to further develop critical peak pricing Nuttall Consulting reviewed United Energy's summer demand incentive charge which was in place prior to 2006, noting that its application is reviewed at least every five years as part of the overall tariff arrangements. Nuttall Consulting noted that some of the cost proposed to investigate critical peak pricing may overlap with these existing costs for tariff review.[373]

As with its proposed expenditure for the use of AMI data, United Energy provided no quantification of the benefits associated with the proposed expenditure for the critical peak pricing program. Nuttall Consulting was not satisfied that the proposed expenditure is either prudent or efficient.[374]

Demand management engagement and the new regulatory test

Nuttall Consulting commented that the expenditure proposed by United Energy is based on the premise that non-network solutions are not sufficiently considered at present in the planning process. Therefore expenditure is required to develop new systems, processes and data dissemination approaches in the forthcoming regulatory control period.[375]

Nuttall Consulting noted that consideration of non-network alternatives is not a new obligation on DNSPs and demonstrated that United Energy has been cognisant of these obligations for many years. Nuttall Consulting considered that the additional expenditure proposed by United Energy is not prudent and does not meet the requirements of the operating expenditure objectives.[376]

Regarding the new obligations imposed by the RIT-D, Nuttall Consulting stated that United Energy did not provide a breakdown or detailed description of the cost build up for this step change. Further the AER has already provided an allowance of $1.39 million for the implementation of the RIT-D which Nuttall Consulting

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371 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 275.

372 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 276.

373 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 277.

374 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 277.

375 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 277–278.

376 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 279.

considered should reasonably enable formalising and aligning existing processes with the new requirements.[377]

Broad based demand management initiatives
Nuttall Consulting noted that other DNSPs have proposed non-network solutions utilising the same providers as described by United Energy. Those other DNSPs also identified associated capex deferrals that enabled consideration of whether these demand side alternatives are efficient or not. United Energy did not identify or quantify the level of capex deferral attributable to its broad based demand management initiatives. As such Nuttall Consulting considered that the additional expenditure proposed by United Energy does not meet the requirements of the operating expenditure objectives.[378]

United Energy also considered that there is anecdotal evidence to suggest that consumers are willing to fund modest initiatives which produce external or ancillary benefits. Nuttall Consulting stated that United Energy did not provide any evidence to support this claim.[379]

Demand management team
Nuttall Consulting stated that United Energy had not provided sufficient information in its initial or revised regulatory proposals to justify the proposed expenditure to establish a demand management team. Nuttall Consulting noted that United Energy is already obliged to consider non-network solutions and has stated that it considers non-network solutions when considering options for meeting network demand. Nuttall Consulting therefore considered that the additional expenditure proposed by United Energy does not meet the requirements of the operating expenditure objectives.[380]

L.5.10.5 Issues and AER considerations

SP AusNet

Non-networks team
As part of review of the National framework for electricity distribution network planning and expansion (distribution planning framework) the AEMC has published draft rules that would require DNSPs to establish and maintain a Demand Side Engagement Strategy. This would involve DNSPs publishing a demand side engagement document, establishing and maintaining a database of non-network case studies and proposals, and establishing and maintaining a demand side engagement register.[381] The AER understands that the Victorian DNSPs were not subject to similar requirements in the 2006–10 regulatory period. The MCE has subsequently stated that Draft rule changes are proposed to be submitted to the AEMC to undergo the full rule

[377] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 279.
[378] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 280.
[379] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 280.
[380] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 280–281.
[381] AEMC, *Distribution annual planning and reporting requirements and the regulatory investment test for distribution draft rule change request (including draft Rules)*, September 2009, p. 3.

change process by December 2010.[382] The MCE supported the proposed framework with a view to the planning arrangements being established in mid 2011 and commencing operation as soon as practicable thereafter.[383]

In the draft decision the AER accepted $1.9 million ($2010) of opex proposed by SP AusNet to meet increased requirements of the distribution planning framework. SP AusNet subsequently agreed with the draft decision.[384] The AER notes that this step change specifically relates to costs associated with the Regulatory Investment Test for Distribution (RIT-D) which is separate to the Demand Side Engagement Strategy and the other activities SP AusNet proposes to undertake with this step change proposal.[385]

Nuttall Consulting commented that the proposed expenditure of $3.75 million (for staffing requirements, training and development and the establishment of data, systems and tools to facilitate non-network planning) appears consistent with the requirements of the distribution planning framework.[386]

Having had regard to SP AusNet's initial and revised regulatory proposals, the analysis provided by Nuttall Consulting and the AER's own analysis the AER is satisfied that the non-networks team opex proposed by SP AusNet reasonably reflects the efficient costs of a prudent DNSP to comply with increased requirements in the distribution planning framework having had regard to the extent that SP AusNet has considered, and made provision for, efficient non-network alternatives and satisfies the requirement of clause 6.5.6(a)(2) and 6.5.6(e)(10).[387]

Deferral of capex

SP AusNet stated that a distributed generation solution will be implemented to defer until 2014 a $7.4 million upgrade to the Benalla zone substation 22kV feeder that was scheduled for 2011. The AER notes that when identifying locations and associated augmentation projects where demand management or distributed generation could potentially achieve capex deferral savings, SP AusNet found that these locations have low load growth, relatively costly augmentation and low volume of load at risk.[388] Nuttall Consulting considered that SP AusNet provided a reasonably robust analysis of likely costs and benefits of the proposed distributed generation solution for the Benalla BN1 feeder.[389]

SP AusNet identified five other locations where a demand management or distributed generation solution can be implemented to achieve capex deferral savings, although

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382 MCE, *MCE response: AEMC review of national framework for electricity distribution network planning and expansion*, Standing Committee of Officials—Bulletin no. 184, 8 October 2010.

383 MCE, *National framework for electricity distribution network planning and expansion*, Ministerial Council on Energy response to Australian Energy market Commission's final report, September 2010, pp. 2–3 and 7.

384 SP AusNet, *Revised regulatory proposal*, p. 210.

385 AER, *Draft decision*, Appendix L, pp. 194–197.

386 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 257–258.

387 Clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(e)(7) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10) of the NER.

388 SP AusNet, *Regulatory proposal*, p. 240.

389 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 258.

specific solutions have not yet been determined for these locations.[390]
Nuttall Consulting noted that the analysis for the remaining locations was less detailed than for the Benalla BN1 feeder, though Nuttall Consulting considered that the level of information provided was reasonable and that the analysis provided by SP AusNet provided a reasonable level of certainty that non-network solutions for capex project deferral may provide the most cost effective options in many of these cases.[391]

Having had regard to SP AusNet's initial and revised proposals and the assessment performed by Nuttall Consulting, the AER considers that SP AusNet has provided a reasonably robust analysis to justify this step change. The AER is satisfied that the proposed expenditure reasonably reflects the efficient costs of a prudent DNSP having had regard to the extent that SP AusNet has considered, and made provision for, efficient non-network alternatives and the substitution possibilities between operating and capital expenditure.[392]

DM programs
SP AusNet stated that it has successfully implemented load control of hot water systems to 8,000 customers in areas such as Leongatha, Wonthaggi, Inverloch and Phillip Island. These have allowed for the deferral of $14.6 million (nominal) in capex on the South Gippsland network in the current regulatory period. SP AusNet is seeking to expand this program to another 90 000 customers in areas of the network experiencing peak demand constraints. SP AusNet expects that this would allow for the deferral of a $7.1 million ($2010) project to reconductor the Wangaratta-Myrtleford line scheduled for 2013.[393]

Nuttall Consulting noted that the timing of the reconductoring project is unclear if the proposed load control of hot water systems project is put into place. However it can be assumed that the reconductoring project is deferred until at least 2016 because it does not appear in the forecasts for the forthcoming regulatory control period.[394]

Nuttall Consulting considered that the information provided by SP AusNet is sufficient to consider that the load control for hot water systems program might reasonably reflect prudent and efficient expenditure.

Having had regard to SP AusNet's initial and revised proposals and the assessment performed by Nuttall Consulting, the AER considers that SP AusNet has provided a reasonably robust analysis to justify the $1.26 million ($2010) step change for hot water system load control. The AER is satisfied that the proposed expenditure reasonably reflects the efficient costs of a prudent DNSP having had regard to the extent that SP AusNet has considered, and made provision for, efficient non-network alternatives and the substitution possibilities between operating and capital expenditure.[395] SP AusNet specifically quantified the benefit associated with the hot

[390] SP AusNet, *Regulatory proposal*, p. 240.
[391] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 258–259.
[392] Clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(2) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10) of the NER.
[393] SP AusNet, *Regulatory proposal*, pp. 242–243.
[394] Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 260.
[395] Clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(2) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10) of the NER.

water system load control in the deferment of $7.1 million ($2010) to reconductor the Wangaratta–Myrtleford line scheduled for 2013.[396]

SP AusNet stated that air-conditioning penetration in residential homes is expected to increase. Reasons include extreme weather events such as those experienced in Victorian in 2008–09 and the relatively low penetration of air-conditioning in Victoria (approximately 70 per cent) compared to South Australia (above 90 per cent). This is expected to place immense demand on network capacity. SP AusNet therefore proposed to trial direct load control on air-conditioners in the Cranbourne/Pakenham and the Epping / Plenty Valley areas because much of the growth in maximum demand is occurring in these residential growth corridors.[397]

SP AusNet stated that the direct load control of air conditioners would deliver benefits by managing peak demand and avoiding augmentation to cater for peak demand. In contrast with the hot water system load control, SP AusNet did not quantify these benefits nor did it provide cost deferrals resulting from this program. The AER agrees with Nuttall Consulting that SP AusNet has not provided sufficient justification to suggest that its direct load control of air conditioning program is either prudent or efficient. Nuttall Consulting noted that SP AusNet has not provided any value for the overall load expected to be reduced by the program or the capex thereby deferred.[398] This indicates that the benefits associated with the program are highly uncertain. The AER therefore is not satisfied that this program meets the requirement of clause 6.5.6(c)(1).

The AER has previously stated that the primary source of funding for demand management expenditure in a regulatory control period should be the forecast opex and capex approved by the AER in the DNSP's distribution determination. The DMIS is provided to DNSPs as a mechanism to encourage the consideration by DNSPs of more innovative, perhaps untested, non-network alternatives.[399] The AER notes that SP AusNet describes this program as a 'trial'.[400] This is supported by the fact that SP AusNet did not provide any value for the overall load expected to be reduced by the program or the capex thereby deferred. Therefore the AER considers that this trial does not meet the requirement of clauses 6.5.6(c)(1) and (2) of the NER. Further the AER considers that the direct load control of air-conditioners project is more appropriately recovered under the DMIS.

Having had regard to SP AusNet's initial and revised proposals and the assessment performed by Nuttall Consulting, the AER considers that SP AusNet has not provided a reasonably robust analysis to justify the $2.03 million ($2010) step change for direct load control of air-conditioners. Further the AER considers that the expenditure of the type proposed by SP AusNet in its direct load control of air-conditioners program is more appropriate under the DMIS. Therefore, the AER is not satisfied that the

396 SP AusNet, *Initial regulatory proposal*, p. 243.
397 SP AusNet, *Initial regulatory proposal*, pp. 243–244.
398 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 260–261.
399 AER, *Demand management incentive scheme Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, Final Decision, April 2009, p. 3.
400 SP AusNet, *Initial regulatory proposal*, p. 245.

proposed expenditure reasonably reflects the efficient costs of a prudent DNSP under clause 6.5.6 of the NER. [401]

Tariffs
SP AusNet is proposing a $1.32 million ($2010) step change to implement TOU tariffs and critical peak demand pricing that is enabled by the rollout of AMI. SP AusNet stated that this expenditure is required for customer notification systems (SMS, page, email) and one full time equivalent staff to monitor and manage the notification process (approximately $250 000 per annum).[402]

Section L.5.6.2 of this final decision sets out the AER's consideration of SP AusNet's proposed opex step change for SMS service in extreme outage events. As set out in section L.5.6.2 the AER considers that the efficient costs required by a prudent operator in the circumstances of SP AusNet to provide such SMS services are $1.5 million ($2010). The AER considers that these SMS systems can be used for the customer notification initiatives proposed by SP AusNet for the introduction of TOU and critical peak demand pricing. The AER therefore considers that the inclusion of expenditure for the customer notification process as part of this step change opex is not consistent with the requirement of clauses 6.5.6(c)(1) and (2) of the NER.

The AER considers that one full time equivalent staff resource to monitor and manage the notification process is an appropriate resource for the forthcoming regulatory control period. The AER considers that $152 000 ($2010) per annum represents a reasonable and conservative estimate for this opex step change and is consistent with clauses 6.5.6(c)(1) and (2) of the NER.

As part of this step change SP AusNet also proposed expenditure for resources to update and maintain additional tariff tables (approximately $10 000 ($2010) per annum).[403] The AER notes that SP AusNet has maintained and updated tariff tables in past regulatory periods and this expenditure should be in the base opex. The AER therefore does not consider that the proposed step change opex for resources to update and maintain tariff tables are consistent with the requirements of clauses 6.5.6(c)(1) and (2) of the NER.

For the reasons discussed above and as a result of the AER's consideration of SP AusNet's revised regulatory proposals and other supporting information, the AER considers that the amount of $0.76 million ($2010) is consistent with a total forecast opex that reasonably reflects the opex criteria.[404] In coming to this view the AER has had regard to the opex factors.[405]

United Energy

Use of AMI data for demand management
In response to an information request from the AER United Energy provided a cost breakdown of the proposed demand management step changes.[406] While the breakdown clarified the allocation of the proposed step change opex to particular

[401] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10).
[402] SP AusNet, *Regulatory proposal*, p. 250.
[403] SP AusNet, *Regulatory proposal*, p. 250.
[404] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2) and 6.5.6(a)(1), 6.5.6(a)(2), 6.5.6(a)(3) and 6.5.6(a)(4).
[405] NER, clauses 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(7), 6.5.6(e)(10).
[406] United Energy, Response to information requested on 21 September 2010, 6 October 2010.

activities, United Energy did not provide the reasoning, assumptions or any information about the inputs. The proposed activities for this component of United Energy's demand management step change included defining the scope of the work, establishing data extraction reporting tools and analying and modelling the data, recommending and investigating feasible projects, and preparing annual reports. United Energy further clarified that the analysis of available data from the AMI program will enable a better understanding of customer behaviour and the information collected will be used to identify new opportunities and methods of demand management.[407]

Secure Partners considered that the costs provided by United Energy 'are reasonable and if anything are conservatively biased.' Secure Partners also considered that the benefits to the industry will substantially exceed proposed costs although it noted that the benefits cannot be quantified with precision.[408] United Energy did not provide the inputs used by Secure Partners, some of which the AER notes is the confidential property of Secure Partners.[409] As such the AER could not test the reasonableness of the inputs used by Secure Energy.

In its revised regulatory proposal United Energy proposed $1.4 million ($2010) for 'Leveraging AMI technology to improve network operational management'.[410] Appendix L.5.7.1 of this final decision details the AER's assessment of this step change and accepted $1.4 million ($2010) as consistent with a total forecast opex that reasonably reflects the opex criteria. United Energy proposed this program to maximise the benefits of the AMI program and stated that some of the benefits include increased capability to manage the network more dynamically and the ability to implement different engineering solutions based on AMI data.[411] The AER considers that this approved expenditure overlaps considerably with the 'Use of AMI data for demand management' step change. The AER therefore considers that the proposed step change is not consistent with clauses 6.5.6(c)(1) and (2) of the NER.

Having had regard to United Energy's initial and revised proposals and analysis done by and for the AER, the AER is not satisfied that the proposed expenditure of $1.0 million (2010) reasonably reflects the efficient costs of a prudent DNSP having had regard to the extent that United Energy has considered, and made provision for, efficient non-network alternatives.[412]

Critical peak pricing

As summarised in the cost breakdown, the activities associated with this component of the proposed demand management step change include investigation of new tariff structures, consultation of new proposed tariff structures with retailers and implementation of new tariffs including staff training and community education.

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407 United Energy, Response to information requested, 9 October 2010, p. 9.

408 Secure Partners, *Appendix: proposed demand response activities*, Prepared for United Energy Distribution, 20 July 2010, p. 6.

409 Secure Partners, *Cover letter to Appendix: proposed demand response activities*, Prepared for United Energy Distribution, 20 July 2010, p. 2.

410 United Energy, *Revised regulatory proposal*, p. 90.

411 United Energy, *Revised regulatory proposal*, p. 90.

412 NER clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(2) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10).

These activities are proposed to be undertaken late in the forthcoming regulatory control period (2014–15).[413]

Nuttall Consulting noted that United Energy's summer demand incentive charge was in place prior to 2006 and is included in United Energy's 2010 tariffs. Nuttall Consulting also noted that the summer demand incentive charge is reviewed at least every five years as part of the overall tariff arrangements. This suggests that some of the costs proposed to investigate critical peak pricing may overlap with the existing costs of these tariff reviews. United Energy did not address this consideration in either the initial or revised regulatory proposals.[414]

The $0.5 million ($2010) proposed by United Energy for this step change is broken down into the following expenditure categories:

- investigation and development of new tariff structures (internal), $70 000 ($2010)
- consultation and development of common tariff structures amongst Victorian distributors, $50 000 ($2010)
- consultation of new proposed network tariffs with retailers, $30 000 ($2010)
- consultation with community groups and energy users, $50 000 ($2010)
- implementation works to introduce new tariffs, provision for staff training and community education and engagement, $300 000 ($2010).

The AER notes Nuttall Consulting's comment that it is difficult to describe the benefits that may be achieved through this program.[415] On the other hand the AER notes that the forthcoming regulatory control period represents a significant change in the circumstances of United Energy with regard to its critical peak pricing strategy. Specifically the roll out of AMI can be expected to provide United Energy greater scope to develop and implement innovative tariff structures such as critical peak pricing. The AER considers that the activities proposed for the critical peak pricing step change are appropriate given the AMI rollout and that the $500 000 ($2010) proposed for these activities appear reasonable.

Having had regard to United Energy's initial and revised proposals and analysis done by and for the AER, the AER is satisfied that the proposed expenditure of $500 000 ($2010) reasonably reflects the efficient costs of a prudent DNSP.[416]

Demand management engagement and the new regulatory test

United Energy proposed $0.5 million to establish systems and collect information necessary to support the RIT-D and the demand side strategy arising out of the distribution planning framework. The cost breakdown summarised the activities

413 United Energy, Response to information requested, 6 October 2010.

414 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 277.

415 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 277.

416 NER clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(2) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10) .

associated with this component of the proposed demand management step change and includes:

- training for new methodologies of assessing solutions to network constraints, $40 000 ($2010)
- development of new estimating and analysis tools, $90 000 ($2010)
- additional administration and reporting requirements (higher costs until methods become entrenched), $370 000 ($2010).[417]

Secure Partners considered that the proposed expenditure forecasts were reasonable and appropriate.[418]

In the draft decision the AER accepted $1.4 million ($2010) of opex proposed by United Energy to meet increased requirements of the RIT-D distribution planning framework.[419] United Energy subsequently agreed with the draft decision.[420] This does not appear to overlap with the costs proposed for demand management engagement and the new regulatory test.

As stated earlier the AER understands that the Victorian DNSPs were not subject to similar requirements to the distribution planning framework in the 2006–10 regulatory control period. The MCE supported the proposed framework with a view to the planning arrangements being established in mid 2011 and commencing operation as soon as practicable thereafter.[421]

Having had regard to United Energy's initial and revised proposals, the analysis provided by Nuttall Consulting and the AER's own analysis the AER is satisfied that United Energy's proposed opex step change for the demand-side engagement strategy and new regulatory test reasonably reflects the efficient costs of a prudent DNSP to comply with increased requirements in the distribution planning framework.[422]

Broad based demand management initiative

United Energy has proposed $6.0 million ($2010) for broad based demand management initiatives. The cost breakdown listed a number of demand management initiatives proposed to be undertaken by United Energy in the forthcoming regulatory control period. United Energy provided further information regarding these broad based demand management initiatives.[423] The information provided by United Energy was high level and did not provide any detail regarding the methodologies or assumptions used to derive the forecast step change amounts. This lack of information from United Energy was also noted by the AER in the draft decision.[424] It appears

[417] United Energy, Response to information requested, 6 October 2010.
[418] Secure Partners, *Appendix: proposed demand response activities*, Prepared for United Energy Distribution, 20 July 2010, p. 9.
[419] AER, *Draft decision*, Appendix L, pp. 194–197.
[420] United Energy, *Revised regulatory proposal*, p. 95.
[421] MCE, *National framework for electricity distribution network planning and expansion*, Ministerial Council on Energy response to Australian Energy market Commission's final report, pp. 2–3 and 7.
[422] NER, clauses 6.5.6(a)(2), 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(e)(7) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10).
[423] United Energy, Response to information requested, 9 October 2010, pp. 7–9.
[424] AER, *Draft decision*, p. 735.

from this limited information that United Energy's broad based demand management initiatives can be classified into either initiatives to trial non-network solutions ($4.15 million, $2010) and investigations and support costs ($3.15 million, $2010). In the cost breakdown United Energy subtracted $1.5 million ($2010)(provision for projects which are deferred) from this total of $7.5 million ($2010) to derive the proposed step change of $6.0 million ($2010). United Energy did not provide any details regarding these deferred projects.

The $4.15 million ($2010) of trial initiatives include:

- small trials of in-home demand management technologies leveraged off the AMI program, $1.55 million ($2010)
- development of direct UED control and signalling technology for demand management, $890 000 ($2010)
- participation in electric vehicle trials, including new tariffs for demand management related to electric vehicles, $360 000 ($2010)
- formal investigation of the benefits of photovoltaic embedded generation and other micro embedded generation as methods of demand management, $50 000 ($2010)
- explore and implement the use of network support capacity from large customers, $1.3 million ($2010).

The investigations and support costs include:

- developing common standards for tariff based demand management structures in conjunction with retailers, $250 000 ($2010)
- direct marketing costs for all programs, $560 000 ($2010)
- education and training programs organised directly by United Energy for selected demand management participants, $420 000 ($2010)
- review of demand management programs implemented by other businesses, $150 000 ($2010)
- provide greater opportunities for community input into non-network solutions for small network constraints, $250 000 ($2010)
- subsidised energy auditing programme for commercial and residential consumers in areas where the network is constrained and long term energy efficiency improvements could provide substantial network benefits, $1.52 million ($2010).

Secure Partners reviewed the proposed activities and associated budgets and considered them to be reasonable and prudent.[425]

As discussed previously the primary source of funding for demand management expenditure in a regulatory control period should be the forecast opex and capex approved by the AER in the DNSP's distribution determination. The DMIS is provided to DNSPs as a mechanism to encourage the consideration by DNSPs of more innovative, perhaps untested, non-network alternatives.[426] The AER notes above that $4.15 million ($2010) of the broad based demand management initiatives can be classified as trials.[427] United Energy has not provided adequate information regarding the benefits such as capex deferrals arising from these programs. The AER considers that these trials do not meet the requirement of clauses 6.5.6(c)(1) and (2) of the NER. The AER considers that the trial initiatives of the type proposed by United Energy are more appropriately recovered under the allowance provided through the DMIS rather than as an opex step change. As set out in the draft decision the AER did not accept the proposed $10 million ($2010) increase to the DMIA because United Energy did not provide adequate justification for why additional DMIA funding should be sought.[428]

Regarding the $3.15 million ($2010) in investigations and support costs it is unclear the extent to which they are connected to and/or reliant upon the $4.15 million ($2010) in trial initiatives. The fact that United Energy subtracted $1.5 million ($2010) from the combined total of the trial initiatives and investigations and support costs to derive the proposed opex for this step change suggests that these two classes of costs are linked. As stated above, the trial initiatives do not meet the requirements of clauses 6.5.6(c)(1) and (2) of the NER. Given the apparent linkage between the trial initiatives and the investigation and support costs, and given the lack of information regarding the benefits arising from the latter, the AER considers that the proposed $3.15 million ($2010) for investigation and support costs do not meet the requirements of clauses 6.5.6(c)(1) and (2) of the NER.

Having had regard to United Energy's initial and revised proposals and supporting material, the assessment performed by Nuttall Consulting and the assessment performed by the AER, the AER considers that United Energy has not provided a reasonably robust analysis to justify the $6.0 million ($2010) step change for broad based demand management initiatives. Therefore, the AER is not satisfied that the proposed expenditure reasonably reflects the efficient costs of a prudent DNSP under clause 6.5.6 of the NER. [429]

Demand management team

United Energy proposed $2.0 million ($2010) to establish a demand management team. The cost breakdown summarises the activities associated with this component of the proposed demand management step change and includes:

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[425] Secure Partners, *Appendix: proposed demand response activities,* Prepared for United Energy Distribution, 20 July 2010, p. 10.

[426] AER, *Demand management incentive scheme Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15,* Final Decision, April 2009, p. 3.

[427] United Energy, Response to information requested, 9 October 2010.

[428] AER, *Draft decision*, p. 735.

[429] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(10).

- direct base salaries for the general management of the demand management programme by the demand management team, $1.17 million ($2010)

- preparation of annual reports for the AER, $100 000 ($2010)

- cost of new systems to determine foregone revenue and costs incurred under the DMIA, $165 000 ($2010)

- funding of independent audits of demand management programs, $135 000 ($2010)

- operating expenses associated with two new dedicated demand management team members, $430 000 ($2010).[430]

Secure Partners did not comment on the reasonableness or prudency of this proposed step change opex.[431]

The AER notes that the purpose of United Energy's demand management team and the associated proposed step change expenditure is similar to that for the demand management team proposed by SP AusNet which is discussed above. Having regard to the opex factors the AER considers that the proposed step change opex of $2.0 million ($2010) for the demand management team is consistent with clause 6.5.6(c)(2) given that United Energy and SP AusNet are sufficiently similar in circumstances.[432]

For the reasons discussed above and as a result of the AER's consideration of United Energy's revised regulatory proposals and other supporting information, the AER considers that the proposed amount of $2.0 million ($2010) is consistent with a total forecast opex that reasonably reflects the opex criteria.[433] In coming to this view the AER has had regard to the opex factors.

Submissions

Regarding Energy Response's submission, the AER has previously stated that the primary source of funding for demand management expenditure in a regulatory control period should be the forecast opex and capex approved by the AER in the DNSP's distribution determination. The AER notes that demand management expenditure proposed in this way must meet the requirements of chapter 6 of the NER particularly clauses 6.5.6 and 6.5.7. The DMIS is provided to DNSPs as a mechanism to encourage the consideration by DNSPs of more innovative, perhaps untested, non-network alternatives.[434] The sections above set out the AER's consideration of the demand management expenditure proposed as opex step changes by SP AusNet and United Energy for the 2011–15 regulatory control period.

[430] United Energy, Response to information requested, 6 October 2010.
[431] Secure Partners, *Appendix: proposed demand response activities*, Prepared for United Energy Distribution, 20 July 2010.
[432] NER, clause 6.5.6(c)(2) and clauses 6.5.6(e)(1), 6.5.6(e) (3), 6.5.6(e) (10).
[433] NER, clauses 6.5.6(c)(2), 6.5.6(a)(1), 6.5.6(1)(3) and 6.5.6(a)(4).
[434] AER, *Demand management incentive scheme Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, Final Decision, April 2009, p. 3.

Regarding the TEC's submission the AER assesses both network and non-network solutions according to the requirements of the NER, particularly clauses 6.5.6 and 6.5.7. The AER does not consider it appropriate to require DNSPs to spend a certain percentage on non-network solutions.

Regarding the CSIRO's submission, table 8.4 of SP AusNet's initial regulatory proposal shows that SP AusNet intends to use the DMIA for the purpose of the opex portion of the energy storage trials.[435] Appendix P of this final decision considers SP AusNet's proposed capex for energy storage trials. In that appendix the AER accepted SP AusNet's proposed $3.18 million ($2010) capex for the energy storage trials (and Officer smart network pilot project) noting that the program would result in the deferment of $15.8 million ($2010) in capex.

L.5.10.6 AER conclusion

For the reasons discussed above the AER considers that $8.2 million ($2010) as proposed by SP AusNet is part of a total forecast opex that reasonably reflects the opex criteria.[436]

For the reasons discussed above the AER considers that $3.0 million ($2010) as proposed by United Energy is part of a total forecast opex that reasonably reflects the opex criteria.[437]

Table L.48 AER final conclusion on demand management expenditure ($'m, 2010)

SP AusNet	United Energy
8.2	3.0

L.5.11 Other step changes

L.5.11.1 AER outcomes monitoring and compliance framework

AER draft decision

In its draft decision the AER set out in chapter 21 the monitoring framework that it intends to establish to monitor the consistency of the Victorian DNSPs with the AER's 2011–15 Victorian distribution determinations, and the service levels delivered to customers. The draft decision also set out the information the AER proposes to collect annually to assess the Victorian DNSPs' compliance with the distribution determination such as information on incentive schemes and approved control mechanisms that are applicable to the DNSP.

The monitoring framework set out replaces the existing annual reporting framework established by the ESCV for monitoring a DNSP's regulatory accounts and network performance indicators. The AER's framework also includes monitoring outcomes of the capex and opex programs proposed by the DNSP. This means that in addition to the reporting of actual opex and capex, and volume information by DNSPs (as is

435 SP AusNet, *Regulatory proposal*, p. 249.

436 NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(c)(3) and 6.5.6(a)(1), 6.5.6(a)(2), 6.5.6(a)(3) and 6.5.6(a)(4).

437 NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(c)(3) and 6.5.6(a)(1), 6.5.6(a)(2), 6.5.6(a)(3) and 6.5.6(a)(4).

currently required under the ESCV framework), the AER will also monitor certain outcome measures for material programs and cost categories. The outcome measures will include measures of the effectiveness of opex and capex expenditure through a number of monitoring and performance measures as well as physical volumes of assets such as the number of new connections. The outcomes monitoring framework also includes outcome measures relating to service standard levels, such as the monitoring of low reliability feeders for Victorian DNSPs, which continues the ESCV's approach.

Victorian DNSP revised regulatory proposals

In their revised regulatory proposals CitiPower, Powercor, JEN and United Energy each claimed that the AER's outcomes monitoring and compliance framework would give rise to additional opex costs for their businesses.[438] CitiPower, Powercor and JEN each forecast their additional costs in their revised regulatory proposals. United Energy provided a forecast to the AER after it had submitted its revised regulatory proposal.[439]

SP AusNet did not claim additional opex costs in its revised regulatory proposal due to the outcomes monitoring and compliance framework. SP AusNet confirmed to the AER that it does not consider it will incur any additional costs in this area above those already included in its base year costs.[440]

CitiPower and Powercor each forecast that their opex costs would increase by $905 000 ($2010) over 2011–15 due to the outcomes monitoring and compliance framework. CitiPower's[441] and Powercor's[442] revised regulatory proposals explained that increased expenditure would be required to develop IT programs to capture the AER's outcomes monitoring and compliance requirements, to meet the costs of CitiPower's and Powercor's regulatory team and Network group in preparing responses to the RIN, for auditing the information being provided to the AER and for legal reviews undertaken of that information. CitiPower and Powercor estimated that the total up-front cost of developing their IT programs would be $1.21 million ($2010), which was apportioned evenly between the two, and each would incur additional annual costs of $60 000 ($2010) for reporting against the AER framework. CitiPower and Powercor were the only Victorian DNSPs to propose up-front expenditure on IT programs for the AER's outcomes monitoring and compliance framework.

JEN forecast that its opex costs would increase by $382 800 ($2010) over 2011–15 due to the outcomes monitoring and compliance framework. JEN's revised regulatory proposal outlined that increased expenditure would be required to meet the cost of additional disaggregated financial reporting, additional reporting and auditing of

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438 CitiPower, *Revised regulatory proposal*, pp. 204–206; Powercor, *Revised regulatory proposal*, pp. 193–196; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 72–74; United Energy, *Revised regulatory proposal*, p. 95.

439 United Energy, Response to information requested on 9 September 2010, 14 September 2010.

440 SP AusNet, Response to information requested on 1 September 2010, 1 September 2010.

441 CitiPower, *Revised regulatory proposal*, p. 206.

442 Powercor, *Revised regulatory proposal*, p. 195.

network performance indicators, and associated internal approval processes for information provided to the AER through a RIN.[443]

United Energy forecast that its opex costs would increase by $400 000 ($2010) over 2011–15 due to the outcomes monitoring and compliance framework.[444] United Energy's revised regulatory proposal commented that its forecast of increased expenditure reflects the incremental costs of additional monitoring measures that it considers the company will be required to undertake, and which was not required under the ESCV's framework.[445] United Energy grouped its forecast costs between costs for making changes to business reporting systems and costs for producing reports and audit assurance processes including audit reports to comply with RIN.[446]

Consultant review

The AER sought advice from Nuttall Consulting on CitiPower's, Powercor's, JEN's and United Energy's opex step change proposals arising from the AER's outcomes monitoring and compliance framework.

In summary, Nuttall Consulting considered that the information currently being captured by the Victorian DNSPs is sufficient to meet the regulatory requirements of the AER's outcomes monitoring and compliance framework. Nuttall Consulting observed that the information required under the framework is information which is already reported to the ESCV, provided to the AER as part of the 2011–15 distribution determination process or recorded by the DNSPs as part of good electricity industry practice. Nuttall Consulting recognised that, in some instances, the requirement to report this information may be a new requirement, but that the information is already collected and stored by the DNSPs. This analysis was supported by JEN's revised regulatory proposal which states that data extraction, review and adjustment are not additional activities arising from the framework.[447]

Nuttall Consulting considered that the annual opex step change costs of $60 000 ($2010) proposed by both CitiPower and Powercor for reporting against the AER's outcomes monitoring and compliance framework would be sufficient to meet the obligations of the framework. Nuttall Consulting considered that CitiPower's and Powercor's proposed annual step change costs suggested an annual expenditure that is more efficient than that proposed by JEN and recommended an annual opex step change cost of $60 000 ($2010) for JEN. Nuttall Consulting advised that the information provided by United Energy was, for all intents and purposes, identical to the information provided by JEN and therefore recommended the same level of expenditure for United Energy as for JEN.[448]

Issues and AER considerations

The outcomes monitoring measures proposed in the draft decision were intended to provide guidance on the framework that the AER intends to implement. Chapter 21 of

443 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 72–74.
444 United Energy, Response to information requested on 9 September 2010, 14 September 2010.
445 United Energy, *Revised regulatory proposal*, p. 95.
446 United Energy, Response to information requested on 9 September 2010, 14 September 2010.
447 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, October 2010, pp. 284-293.
448 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, October 2010, p. 294.

this final decision further outlines the AER's outcomes monitoring and compliance framework. The framework set out in this final decision is substantively the same as that set out in the draft decision. The AER will undertake further consultation with Victorian DNSPs and other stakeholders to determine the specific form of the outcome measures for Victorian DNSPs to report against as part of a separate RIN process.

The AER considers that the Victorian DNSPs will incur additional costs to meet the obligations under the AER's outcomes monitoring and compliance framework. However the AER is of the view that as the information required by the AER is already reported to the ESCV, provided to the AER as part of the 2011–15 distribution determination process or currently recorded by the DNSPs, additional up-front expenditure for the development of IT programs, proposed by Citipower and Powercor, will not be required to comply with the framework.

Although the AER framework set out in this final decision replaces the existing annual reporting framework established by the ESCV and allows for additional reporting parameters, the AER does not consider that the framework extends beyond information that is already collected and stored by the Victorian DNSPs for regulatory or business purposes, the costs of which are reflected in their base year opex.

The AER therefore does not accept the Victorian DNSPs' proposed step changes to meet the requirements of the AER's outcomes monitoring and compliance framework. The AER does not consider that the proposed expenditure reasonably reflects the efficient costs or the costs that a prudent operator would require to achieve the operating expenditure objectives.[449] The AER considers that an allowance of $60 000 ($2010) per annum, as recommended by Nuttall Consulting, is sufficient to meet the obligations of the framework and reasonably reflects the efficient costs or the costs that a prudent operator would require to comply with a regulatory obligation or requirement under the NER.[450]The AER considers that this amount is sufficient having had regard to Nuttall Consulting's advice and because it is within a reasonable range of the costs for annual reporting proposed by JEN, United Energy, Citipower and Powercor, excluding up-front expenditure for the development of IT programs.

For the reasons discussed above the AER does not consider that the expenditure proposed by CitiPower, Powercor, JEN and United Energy to meet the requirements of the AER's outcomes monitoring and compliance framework is part of a total forecast opex that reasonably reflects the opex criteria. In coming to this view the AER has had regard to the opex factors.[451]

AER conclusion

The AER is satisfied that its estimate of the step change to meet the requirements of the AER's outcomes monitoring and compliance framework in table L.49 forms part of a total forecast opex that reasonably reflects the opex criteria.

[449] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(1), 6.5.6(a)(2), 6.5.6(a)(3), 6.5.6(a)(4).
[450] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(2).
[451] NER, clauses 6.5.6(e)(1), 6.5.6(e)(5).

Table L.49 AER conclusion on step change costs of complying with the AER's outcomes monitoring and compliance framework ($'000, 2010)

CitiPower	Powercor	JEN	United Energy
300	300	300	300

Source: AER analysis.

L.5.11.2 Tariff class reassignment disputes

AER draft decision

The tariff class assignment and reassignment procedures (the procedures) for direct control services for the forthcoming regulatory control period were set out in appendix G of the draft decision.

Clause 6 required the Victorian DNSPs to notify customers in writing of the tariff class to which they had been assigned or reassigned, prior to the assignment or reassignment occurring.

Clause 7 of the procedures required the Victorian DNSPs to inform customers of the tariff class assignment and reassignment dispute resolution mechanisms available. Clause 7.a. of appendix G of the draft decision required that tariff class assignment and reassignment disputes are reviewed under each Victorian DNSP's internal review system as a first step. Under clause 7.b. a customer was entitled to escalate the matter as appropriate to the Energy and Water Ombudsman (Victoria) (EWOV) if the dispute was not resolved under the DNSP's internal review system. Under clause 7.c. the customer was entitled to escalate the matter to the AER if the dispute was not resolved under the DNSP's internal review system or by EWOV.

Victorian DNSP revised regulatory proposals

CitiPower, Powercor, JEN and SP AusNet stated that the requirement to notify customers of tariff class assignments in clause 6 of appendix G of the draft decision imposed unnecessary costs.[452] CitiPower, Powercor and JEN stated that customers need not be notified of tariff class assignments because customers have either implicitly or explicitly agreed to the tariff class to which they have been assigned when they enter into a contract with a retailer or distributor as the case may be.[453]

CitiPower, Powercor, JEN and SP AusNet stated that the involvement of the EWOV in clause 7.b. of the procedures was unnecessary and costly and suggested that it be removed from the procedures.[454] JEN and SP AusNet considered that if the AER

[452] CitiPower, *Revised regulatory proposal*, pp. 80–81; Powercor, *Revised regulatory proposal*, pp. 74–75; JEN, *Revised regulatory proposal*, pp. 29–31; SP AusNet, *Revised regulatory proposal*, pp. 370–371.

[453] CitiPower, *Revised regulatory proposal*, pp. 80–81; Powercor, *Revised regulatory proposal*, p. 75; JEN, *Revised regulatory proposal*, p. 29.

[454] CitiPower, *Revised regulatory proposal*, pp. 61, 82–83; Powercor, *Revised regulatory proposal*, pp. 57, 76–77; Jemena, *Revised regulatory proposal*, p. 32; SP AusNet, *Revised regulatory proposal*, pp. 371–372.

retains EWOV involvement in the procedures, the Victorian DNSPs must be compensated for the costs incurred.[455]

United Energy did not comment on additional costs related to the procedures in their revised regulatory proposal. United Energy subsequently provided estimated costs associated with complying with the requirements of appendix G.[456]

The step changes proposed by the Victorian DNSPs for the requirements of appendix G of the draft decision are outlined in table L.50.

Table L.50 Proposed tariff class reassignment step changes ($'000, 2010)

CitiPower	Powercor	JEN	SP AusNet	United Energy
1069	2337	2006[a]	1012	2363[a]

(a) Includes EWOV costs.
Source: CitiPower, *Revised regulatory proposal*, p. 207; Powercor, *Revised regulatory proposal*, p. 197; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 11; SP AusNet, Response to information requested on 11 August 2010, 18 August 2010, p. 239; United Energy, Response to information requested on 9 September 2010, 9 September 2010.

Issues and AER considerations

As discussed in chapter 4 of this final decision, the AER has amended clause 6 of appendix G in this final decision such that Victorian DNSPs are not required to notify customers of tariff class assignments (see clause 6 of appendix G of this final decision). The Victorian DNSPs will therefore not require the expenditure proposed to comply with requirement to notify customers of tariff class assignments under clause 6 of appendix G of the draft decision.

As detailed in chapter 4 of this final decision the AER considers that the inclusion of EWOV in the tariff class assignment and reassignment procedures is not a new requirement. EWOV considers that tariff class assignment and reassignment dispute resolution is currently within its jurisdiction and has provided evidence that it has dealt with tariff assignment and reassignment disputes in the current and in past regulatory periods.[457] Clause 7.b. of appendix G of the draft decision is therefore not a new regulatory requirement for the Victorian DNSPs having regard to clause 6.5.6(a)(2) of the NER.

More importantly the costs associated with this requirement are avoidable costs as they acts to incentivise the Victorian DNSPs to assign or reassign customers to tariff classes appropriately in the first instance, and to develop good internal dispute resolution mechanisms and processes in the second instance. The AER therefore considers that the proposed step changes for tariff class assignment and reassignment disputes that get escalated to EWOV do not reasonably reflect the efficient cost of a prudent DNSP under the NER.

455 JEN, *Revised regulatory proposal*, p. 32; SP AusNet, *Revised regulatory proposal*, p. 371.
456 United Energy, *Response to information requested on 9 September 2010*, 9 September 2010.
457 EWOV, email to AER, 29 September 2010.
Note that tariff class assignments and reassignments can be considered as a subset of tariff assignments and reassignments.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of the Victorian DNSPs' revised regulatory proposals and other supporting information, the AER considers that the amounts proposed by the Victorian DNSPs in table L.50 are not consistent with a total forecast opex that reasonably reflects the opex criteria.[458] In coming to this view the AER has had regard to the opex factors.[459]

L.5.11.3 Defined benefit fund and accumulation fund contributions

AER draft decision

None of the Victorian DNSPs proposed a step change for defined benefit fund and accumulation fund contributions in their initial regulatory proposals. Consequently, the AER did not provide the Victorian DNSPs a step change for superannuation contributions in the draft decision.

However, the AER considered that the impact of the recent global financial crisis was such that any actuarial adjustments related to defined benefit scheme contributions reflected in the reported base year costs were unlikely to be consistent with the level of costs expected to occur in the forthcoming regulatory control period. The AER adjusted the base year opex to reflect this.[460]

Victorian DNSP revised regulatory proposals

CitiPower and Powercor did not remove from their base opex for 2009 superannuation costs associated with the defined benefit superannuation scheme. CitiPower and Powercor noted that over the forthcoming regulatory control period the proportion of their employees who will be active members of the defined benefit scheme will decline as they retire and that all new employees must join the accumulation fund. CitiPower and Powercor proposed a superannuation step change representing the net impact over the forthcoming regulatory control period of the projected decrease in defined benefit fund contributions and the increase in accumulation fund contributions, as shown in table L.51.[461]

Table L.51 Victorian DNSP proposed step change for defined benefit fund and accumulation fund contributions ($'000, 2010)

CitiPower	Powercor
1341	3561

Source: CitiPower, *Revised regulatory proposal*, p. 188; Powercor, *Revised regulatory proposal*, p. 178.

Issues and AER considerations

The AER notes that over the forthcoming regulatory control period the number of CitiPower and Powercor employees on defined benefit schemes will decrease as they retire and that the number of staff on accumulation schemes will increase. The AER therefore considers it reasonable that the accumulation fund contributions paid by

458 Clauses 6.5.6(c)(2), 6.5.6(c)(3) and 6.5.6(a)(2).
459 Specifically opex factors (1), (2), and (3).
460 AER, *Draft decision*, p. 244.
461 CitiPower, *Revised regulatory proposal*, p. 188; Powercor, *Revised regulatory proposal*, p. 177.

CitiPower and Powercor will increase over the forthcoming regulatory control period. However, the AER notes that, as discussed in chapter 7 of this final decision, it has not removed defined benefit scheme contributions from base year expenditure in this final decision.

The AER reviewed the superannuation step change models provided by CitiPower and Powercor in support of their proposed step change for defined benefit fund and accumulation fund contributions.[462]

Mercer projected defined benefit superannuation expenses for the forthcoming regulatory control period for CitiPower and Powercor. These projections included the number of members of the defined benefit scheme.[463] CitiPower and Powercor assumed that the decrease in the number of members of the defined benefit scheme would be equal to the increase in employees on the accumulation scheme. CitiPower and Powercor then multiplied this increase in employees on the accumulation scheme by the average annual salary, multiplied by 9 per cent, to calculate the increase in accumulation fund contributions. The AER notes that the projected decrease in defined benefit fund expenses is greater than the projected increase in accumulation fund expenses.[464]

CitiPower and Powercor then applied labour cost and scale escalation to the projected accumulation fund expenses to calculate the total step change.[465]

The AER notes that CitiPower and Powercor applied labour cost and scale escalation to the total forecast accumulation fund expense, not just the increase in accumulation fund expenses due to employees on the defined benefit scheme being replaced by employees on the accumulation scheme. The AER considers that this will double count the labour cost and scale escalation of superannuation expenses, which are already escalated to the extent that these costs are reflected in the base year expenditure.

Further, the AER notes that by applying scale escalation CitiPower's and Powercor's superannuation step change models effectively assume that the increase in employees on accumulation schemes is greater than the decrease in employees on the defined benefit scheme. Thus the step changes proposed by CitiPower and Powercor represent more than the costs of employees on the defined benefit scheme being replaced by employees on accumulation schemes.

AER conclusion

For the reasons discussed above, the AER is not satisfied that the defined benefit fund and accumulation fund contributions step change proposed by CitiPower and Powercor is consistent with a total forecast opex that reasonably reflects the efficient costs that a prudent operator would require to achieve the opex objectives. The AER

462 CitiPower, *Revised regulatory proposal*, Attachment 13; Powercor, *Revised regulatory proposal*, Attachment 13.

463 CitiPower, *Revised regulatory proposal*, Appendix 123; Powercor, *Revised regulatory proposal*, Appendix 123.

464 CitiPower, *Revised regulatory proposal*, Attachment 13; Powercor, *Revised regulatory proposal*, Attachment 13.

465 CitiPower, *Revised regulatory proposal*, Attachment 13; Powercor, *Revised regulatory proposal*, Attachment 13.

considers that the proposed step changes double count costs already provided for in the base year expenditure and that the base year expenditure is consistent with the level of costs expected to occur in the forthcoming regulatory control period.

L.5.11.4 Superannuation guarantee levy

AER draft decision

None of the Victorian DNSPs proposed a step change for changes to the superannuation guarantee levy in their original regulatory proposals. Consequently, the AER did not provide the Victorian DNSPs with a step change for superannuation contributions in the draft decision.

Victorian DNSP revised regulatory proposals

CitiPower and Powercor noted that, following the Henry Review, the Australian Government announced an intention to progressively increase the superannuation guarantee levy to 12 per cent by 2019–20. CitiPower and Powercor stated that, should this policy be legislated, the superannuation liability of CitiPower and Powercor would be increased by the amounts in table L.52.[466]

Table L.52 Victorian DNSP proposed step change for increases to the superannuation guarantee levy ($'000, 2010)

CitiPower	Powercor
236	1289

Source: CitiPower, *Revised regulatory proposal*, p. 189; Powercor, *Revised regulatory proposal*, p. 179.

Issues and AER considerations

The proposed changes to the superannuation guarantee levy, announced by the Australian Government on 2 May 2010, have not been legislated.[467] The AER notes that the proposed changes to the superannuation scheme are to be funded by the proceeds from the MRRT, therefore the proposed superannuation changes are subject to the same uncertainties as the proposed changes to the corporate tax rate discussed in chapter 12. In order to maintain consistency with its approach to the company tax rate changes, the AER considers that it would be inappropriate to allow an opex step change to address the proposed changes to the superannuation guarantee rate, as the implementation of the policy is too uncertain.

The AER notes that Dr Ken Henry, Secretary to the Treasury, has stated that analysis shows that past increases in the superannuation guarantee have come from employee's gross wages rather than company profits, and that 'the superannuation guarantee is regarded by both employers and employees as a different way of receiving an increase in wages'.[468]

[466] CitiPower, *Revised regulatory proposal*, p. 189; Powercor, *Revised regulatory proposal*, pp. 178–179.

[467] The Hon Wayne Swan, Treasurer, Australian Government and The Hon Kevin Rudd, Prime Minister, Australian Government, *Stronger, fairer, simpler: A tax plan for our future*, Media release, 2 May 2010.

[468] Dr Ken Henry, Senate Estimates, 27 May 2010.

AER conclusion

For the reasons discussed above the AER is not satisfied that the superannuation guarantee levy step change proposed by CitiPower and Powercor is consistent with a total forecast opex that reasonably reflects the efficient costs that a prudent operator would require to meet its obligations under superannuation legislation.

L.5.11.5 Transmission related, inter-DNSP and avoided TUOS costs step change

AER draft decision

The draft decision explained that transmission related, inter-DNSP and avoided TUOS costs were not recoverable under clause 6.18.7 the NER. These payments or costs are otherwise known as relating to costs for:

- connection to the transmission network
- avoided transmission use of system costs (payments to embedded generators)
- inter-DNSP charges.[469]

United Energy and SP AusNet submitted to the AER that transmission connection costs did not meet the NER definition of recoverable costs and that a rule change was required to correct this.[470] In the draft decision the AER agreed with SP AusNet's and United Energy's interpretation that TUOS is defined under the NER so as to exclude transmission connection costs. The AER also considered that inter-DNSP and avoided TUOS costs were excluded.

DNSPs' revised regulatory proposals

CitiPower and Powercor proposed the inclusion of a new term in the weighted average price cap and side constraint formulae to address transmission related costs.

On this basis they did not propose a step change for these costs. However, they considered that if the AER disagreed with their proposed approach, it should include an opex step change allowance to permit transmission cost recovery.[471]

JEN proposed substituting the current maximum transmission revenue control with a maximum pass through revenue control that they believed would permit recovery of all pass through amounts, including transmission connection costs.[472]

Although noting that the AEMC was reviewing the Victorian DNSPs' proposed rule change to clause 6.18.7 of the NER, JEN requested that the AER consult on the treatment of transmission cost recovery.[473]

United Energy considered that clause 6.18.7 of the NER did not allow recovery of transmission connection costs. It therefore proposed a rule change to the AEMC, such that transmission connection costs could be recovered by the Victorian DNSPs.[474]

469 AER, *Draft decision*, p. 64–66.
470 United Energy, *Regulatory proposal*, July 2010, pp. 201–202; SP AusNet, *Regulatory proposal*, July 2010, p. 350.
471 CitiPower, *Revised regulatory proposal*, p. 60; Powercor, *Revised regulatory proposal*, p. 56.
472 JEN, *Revised regulatory proposal*, p. 34.
473 JEN, *Revised regulatory proposal*, p. 34.

United Energy observed that the AEMC's rule determination may not be made before the Victorian DNSPs submit their pricing proposals to the AER in November 2010. United Energy considered that it was therefore necessary for the AER to investigate measures that would permit the Victorian DNSPs to recover these costs.[475]

In the absence of the rule change concluding before the November 2010, United Energy stated that:

> The AER should ensure that the distribution determination includes statements to enable DNSPs to recover transmission exit charges.[476]

United Energy also stated that transmission connection services fall within the definition of direct control services and that the AER's final decision could determine them as such, thereby ensuring transmission connection services were recovered through the Victorian DNSPs' annual pricing proposals.[477] United Energy noted that the AER's distribution determinations for New South Wales, South Australia and Queensland had previously approved recovery of transmission connection costs under clause 6.18.7 of the NER. United Energy considered that the AER should do the same in relation to the Victorian DNSPs. [478]

SP AusNet submitted that a cost pass through, with a reduced materiality threshold, was the appropriate arrangement to permit recovery of all transmission connection costs.[479]

Failing this, SP AusNet proposed providing the AER with the most up to date estimate of expenditures on transmission related, inter-DNSP and avoided TUOS costs for inclusion in SP AusNet's proposed pass-through formula. [480] SP AusNet recommended that this formula be included in the AER's final decision.[481]

SP AusNet stated that failure by the AER to accept either option would not be consistent with the revenue and pricing principles in the NEL, which require that a DNSP should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services.

Issues and AER considerations

The AER notes that United Energy lodged a rule change proposal with the AEMC in June 2010 seeking amendments that would permit recovery of transmission related, inter-DNSP and avoided TUOS costs in Victoria. Fundamentally, the proposal seeks recovery of these costs consistent with historic jurisdictional experience and in line with the AER's distribution determinations for NSW and South Australia.[482]

The AER notes the different arrangements proposed by the Victorian DNSPs in their revised regulatory proposals for recovering transmission related, inter-DNSP and

474 United Energy, *Revised regulatory proposal*, p. 280.
475 United Energy, *Revised regulatory proposal*, p. 280.
476 United Energy, *Revised regulatory proposal*, p. 280.
477 United Energy, *Revised regulatory proposal*, p. 280.
478 United Energy, *Revised regulatory proposal*, p. 280.
479 SP AusNet, *Revised regulatory proposal*, p. 373.
480 ibid, p. 378.
481 ibid.
482 See AEMC website

avoided TUOS costs from customers, specifically, recovery as opex or as a pass through under the building block and recovery through an amendment to the weighted average price cap formula. The AER did not further consult given this issue was raised in the draft decision (and that the AEMC's review is currently underway) and it has carefully considered each of the Victorian DNSPs' proposed arrangements.

In considering this issue, the AER notes that the AEMC did not treat the proposed Rule change as non-controversial and at the time of the final decision the AEMC is awaiting submissions to the consultation paper it published. It noted that the issues were complex, including the definition of transmission services and how costs should be recovered.[483]

The AEMC's final decision on transmission related, inter-DNSP and avoided TUOS costs recovery is expected in 2011. The AER considers that it is not appropriate to pre-empt the AEMC's decision on the costs that can be recovered through clause 6.18.7 of the NER.

The AER has submitted to the AEMC that it supports a rule change to allow transmission related, inter-DNSP and avoided TUOS costs that are incurred by DNSPs in the supply of standard control services to be recovered through clause 6.18.7.[484]

As it also submitted to the AEMC, the AER recognises that transmission related, inter-DNSP and avoided TUOS costs have been recovered through a mechanism similar to clause 6.18.7 of the NER under previous decisions of the ESCV and other jurisdictional regulators. It has been past regulatory practice that these costs are recovered through annual pricing approval processes, that is, outside of the five year building block determination. The AER considers that this approach is appropriate given that the nature of these costs raises difficulties in forecasting their quantum under a five year building block determination and carries with it a high risk of over or under recovery of the costs from consumers. That is, attempting to allow transmission related, inter-DNSP and avoided TUOS costs to be included in a DNSPs operating expenditure forecasts when assessing its building block revenues is likely to result in under or over recovery of these costs. The AER does not consider that such an outcome would be consistent with the national electricity objective or the revenue and pricing principles. A submission to the AEMC by United Energy on behalf of all Victorian DNSPs supported this view.[485]

However, as discussed in chapter 16 of this final decision, the AER understands that these are legitimate costs the Victorian DNSPs will incur and considers that the regulatory regime should arguably allow for the recovery of these costs. The AER has therefore nominated a pass through event for the Victorian DNSPs, namely the network charges pass through event, to allow for the recovery of these costs pending

483 AEMC, *DNSP Recovery of Transmission-related Charges, Consultation paper,* 2 September 2010, pp. 7–9.

484 AER, *ERC0114 – National Electricity Amendment (DNSP recovery of Transmission-related charges) Rule 2010*, 1 October 2010.

485 United Energy*, Response to AEMC questions about the recovery of transmission connection charges and other costs: submission on behalf of the Victorian electricity distributors,* September 2010, p. 2.

the finalisation of the AEMC's rule change process. Given this, forecast opex to cover these costs is not required.

AER conclusion

As the AER has allowed for these costs to be recovered through a nominated pass through event, the AER is not satisfied that the Victorian DNSPs' proposed forecast opex for transmission related, inter-DNSP and avoided TUOS costs forms part of a total forecast opex that reasonably reflects the opex criteria.

As noted above, chapter 16 of this final decision considers the Victorian DNSPs' proposal to recover transmission related, inter-DNSP and avoided TUOS costs through the pass through mechanism. CitiPower's, Powercor's and United Energy's proposal to recover these costs through additional parameters in the WAPC is considered in chapter 4 of this final decision on the control mechanism for standard control services.

For the reasons discussed above, Victorian distribution tariffs for 2011 will include only those TUOS costs that can be recovered through clause 6.18.7 of the NER.

L.5.12 Additional step changes proposed by CitiPower

CitiPower proposed one additional step change relating to the West Melbourne terminal station.

L.5.12.1 West Melbourne terminal station

AER draft decision

The AER noted that load forecasts for West Melbourne terminal station identified an emerging network constraint and that a response would be required by CitiPower to avoid the loss of supply and minimise the load at risk.

The AER also noted that the 2009 *Transmission connection planning report* identified four options for managing the contingent risks at West Melbourne terminal station and that Nuttall Consulting concluded that it would have been prudent if the costs and benefits of these options had been considered. The AER considered that CitiPower's options analysis was incomplete and that it had failed to reasonably demonstrate the efficiency of the chosen option over the alternatives.

Consequently, the AER was not satisfied that CitiPower's proposed expenditure for the West Melbourne terminal station reasonably reflected the efficient costs a prudent operator in the circumstances of CitiPower would require and removed the proposed step change from CitiPower's opex allowance.

Victorian DNSP revised regulatory proposals

CitiPower stated that it had reviewed each of the four options identified in the *Transmission connection planning report 2009* and decided that the demand management option was the only prudent and efficient option.[486]

[486] CitiPower, *Revised regulatory proposal*, p. 198.

CitiPower provided its reasons for rejecting the other options and stated that the demand management option was the only that would not compromise network security under the majority of peak demand days.[487]

CitiPower's forecast of the direct costs of this program is set out in table L.11.

Table L.53 CitiPower proposed West Melbourne terminal station demand management step change, ($'000, 2010)

2011	2010	2103	2014	2015	Total
2168	2576	2508	–	–	7251

Source: CitiPower, *Revised regulatory proposal*, p. 202.

Submissions

The Total Environment Centre (TEC) stated that the AER did not compare the cost of the WMTS project with the cost of a black-out. TEC also commented that the AER's criticism of CitiPower for providing only one demand-side service provider only reflects the absence of a market for demand-side solutions. This in turn reflects the failure of energy market structures to encourage such a market.[488]

TEC commented that the AER's criticism that CitiPower has not considered other options to address the energy at risk draws attention to the fact that almost all augmentation proposals have not considered other options such as demand management and distributed generation.[489]

Consultant review

Nuttall Consulting noted that only one demand side service provider provided a cost estimate for the demand management option for the WMTS project. However, given the limited market for demand management options and the role the demand side service provider has as an aggregator of demand management proponents, Nuttall Consulting considered these costs as the best estimate at this time.[490]

Based upon additional information provided by CitiPower on alternative options, Nuttall Consulting considered that a complete alternative to demand management may not be the most prudent and efficient option. On the other hand it was unclear to Nuttall Consulting why it would not be more efficient to use distribution load transfer to offset the need for the level of demand management proposed noting that distribution load transfers will be used to manage the shortfall between the load at risk and the demand management forecast. Therefore Nuttall Consulting considered that a combination of options involving some demand management and other measures may be the preferred solution.[491]

487 CitiPower, *Revised regulatory proposal*, p. 198.
488 TEC, Submission, 24 August, p. 7.
489 TEC, Submission, 24 August, pp. 7–8.
490 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 232.
491 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 233.

Issues and AER considerations

The AER notes that Nuttall Consulting's considered that 'it is unlikely that a complete alternative to the demand management option will be found to be the most prudent and efficient option.'[492]

Further, Nuttall Consulting considered that the estimated shortfall between the load at risk and the demand management option will be managed by other measures, including distribution load transfers. Based on this information and CitiPower's cost model Nuttall Consulting recommended that a combination of demand management solutions with other measures may be the preferred option, noting however that this may expose the network to greater energy risk.[493]

The level of risk posed on the network by a lower level of demand management offset by greater distribution load transfer (and other measures) is unclear. However the AER is satisfied that CitiPower has provided reasonably robust analysis to suggest that the proposed expenditure for demand management at West Melbourne terminal station reasonably reflects the efficient costs of a prudent DNSP to manage expected demand and maintain its network.

AER conclusion

For the reasons discussed above, the AER considers $7.251 million ($2010) as proposed by the is part of a total forecast opex that reasonably reflects the opex criteria.

L.5.13 Additional step changes proposed by JEN

L.5.13.1 AER draft decision

Of the thirteen additional step changes to those discussed above proposed by JEN, the AER:

- accepted JEN's withdrawal of the zone substation ladder inspection program proposal as it was already included in the base year opex
- accepted the Sunshine depot restoration costs step change as a change in JEN's operating environment and that the costs proposed reflected those incurred by a prudent and efficient DNSP in JEN's circumstances
- did not accept the other additional step change proposals as it considered that JEN had either:
    - not been able to identify a special regulatory trigger, or
    - not been able to demonstrate that there has been a change in its operating environment, or

[492] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 233.

[493] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 233.

- received funding to address these regulatory requirements or obligations in previous regulatory determinations.

L.5.13.2 Victorian DNSP revised regulatory proposals

JEN accepted the AER's draft decision to not accept step changes for:

- zone substation transformer noise tests
- zone substation fall arrest inspection
- [confidential]
- zone substation ladder inspection
- a protection setting review
- [confidential]
- [confidential]
- earth testing in non CMEN areas

JEN also accepted the AER's draft decision on the inclusion of a step change for:

- Sunshine depot restoration costs—forecast $25 000 ($, 2010)

JEN did not accept the AER's draft decision on the following step changes:

- neutral condition monitor (previously WireAlert neutral condition monitors)—forecast $1.5 million ($2010)[494]
- [confidential[495]
- non pole distribution substation routine maintenance—forecast $0.6 million ($2010)[496]
- overhead mounted switchgear inspection and maintenance—forecast $1.0 million ($2010)[497]
- Broadmeadows site relocation—forecast $2.1 million ($, 2010)[498]
- distribution substation cleaning, gardening and security—forecast $1.0 million ($2010)[499]

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494 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 37–41.
495 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 43.
496 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 44–45.
497 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 44–45.
498 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 61–62.
499 ibid. pp. 43–44.

L.5.13.3 Submissions

EziKey Group who trade as WireAlert provided a submission (WireAlert submission) in support of JEN's proposal to implement a pilot trial of the WireAlert device.[500] The WireAlert submission proposed that an impaired or broken neutral is one of the major public risks for DNSPs and that the implementation of the WireAlert device, based on its analysis in other jurisdictions, would produce a 'step change' improvement in public safety.[501] The WireAlert submission also noted alternate solutions, funding offsets and other benefits that are possible through the use of the WireAlert device.

Energy Safe Victoria (ESV) has also provided its views on the neutral condition monitors program as part of its review of electricity distributors proposed safety related expenditure.[502]

L.5.13.4 Consultant review

Nuttall Consulting reviewed the unit cost for this proposal and concluded that the $40 per neutral condition monitor as proposed by JEN was reasonable.[503]Nuttall Consulting's review is discussed further below.

L.5.13.5 Issues and AER considerations

In assessing the proposals that JEN resubmitted for this category of step changes, the AER has reviewed both the information provided in JEN's initial and revised regulatory proposals as well as all relevant supporting information.

Neutral condition monitors

JEN considered that its neutral condition monitor step change proposal was triggered by a changed regulatory obligation and reflects the efficient costs a prudent operator would require in meeting the opex objectives, particularly clauses 6.5.6(a)(2), (3) and (4) of the NER.[504] JEN also linked this proposal to the Wilson Cook criteria in the New South Wales final decision.[505] JEN quoted historical figures for shocks caused by neutral screen services and noted that there was a trend of deterioration in neutral screen cables which were contributing to the number of network asset-related shocks and tingles. JEN proposed five options to manage this risk, settling on the option it put forward in its initial proposal. This, JEN noted, would reduce the relevant risk to 'as low as reasonably practicable' as required by the general duty in the *Electricity Safety Act 1998*. The AER further notes that JEN proposed that the WireAlert trial would be targeted on known high risk areas to 'maximise the effectiveness of the expenditure'.[506]

The AER notes that of the five competing options put forward by JEN the WireAlert trial was selected as it would improve public safety, reduce the risks associated with electric shocks and offset operating costs for periodic neutral service testing. Of the

500 EziKey Group Pty Ltd, Submission, August 2010.

501 EziKey Group Pty Ltd, Submission, August 2010, pp. 2–3.

502 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 7.

503 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 303.

504 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 37–41.

505 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 41.

506 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 40.

competing alternative options proposed, the AER notes that one related to an integration of neutral testing within the advanced metering infrastructure hardware.[507]

JEN noted that whilst quotes for the integration of neutral testing within the advanced metering infrastructure hardware were around half that of the WireAlert device no commercial product was currently available and that this functionality is not currently a minimum specification for these meters.[508]

The EziKey WireAlert submission supported the use of its product based on the results achieved in Tasmania and trials across Australia.[509] The EziKey WireAlert submission also considered that a full roll out of the WireAlert device across Victoria would produce a step change in improvement in public safety and considered that a demonstration of this would be through the trial performed on JEN's network.

In support of the use of the WireAlert device the EziKey WireAlert submission contained a supporting document from ESV which stated:

> ESV views the WireAlert device as emerging technology and considers that it would be appropriated to gain experience in the operation of the device on the Victorian network by conducting a trial.[510]

ESV further noted its support for this neutral condition monitor program in its review of electricity distributors' proposed safety related expenditure recognising its support due to:

- the level of electric shocks experienced by members of the public due to loss of neutral integrity
- the length of time for replacement of services types with known issues
- the likelihood of problems emerging with other types of services.[511]

The AER acknowledges ESV's support for the EziKey WireAlert device trial and is also supportive of the use of emerging technologies where appropriate. The AER further acknowledges the EziKey WireAlert submission's claims of possible funding offsets and other benefits that are possible through the use of WireAlert device.

Both the JEN revised regulatory proposal and the WireAlert submission refer to the risks involved with faulty or broken neutrals and the AER considers a trial approach of this technology could assist in mitigating these risks.

The EziKey WireAlert submission quoted an average cost of $50 per household for the rollout in Tasmania.[512] JEN has proposed a cost of $40 per unit for this trial.[513] As stated above, Nuttall Consulting reviewed the unit cost for this proposal and concluded that the $40 per neutral condition monitor as proposed by JEN was

507 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 39.
508 JEN, *Revised regulatory proposal,* Appendix 7.2, confidential, p. 39.
509 EziKey Group Pty Ltd, Submission, August 2010, p. 2.
510 EziKey Group Pty Ltd, Submission, August 2010, Appendix 1, p. 9.
511 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 7.
512 EziKey Group Pty Ltd, Submission, August 2010, p. 5
513 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 39.

reasonable.[514] Based on this the AER considers JEN's proposal reflects the benchmark opex that would be incurred by an efficient DNSP in undertaking this rollout.[515]

Based on this the AER considers that the forecast cost proposed by JEN is consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria. This proposal will contribute to JEN's objectives to maintain the quality, reliability and security of supply of standard control services and the reliability, safety and security of the distribution system through the supply of standard control services.[516]

[confidential]

[commercial in confidence].[517]

[commercial in confidence]

[commercial in confidence].[518]

[commercial in confidence].[519]

[commercial in confidence].[520]

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[514] Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 303–304.

[515] NER, clause 6.5.6(e)(4).

[516] NER, clauses 6.5.6(c)(1), 6.5.6(a)(3) and 6.5.6(a)(4).

[517] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 43.

[518] JEN, *Regulatory proposal,* Appendix 10, confidential, p. 22; AER, *Draft decision,* June 2010, p. 412.

[519] AER, *Draft decision*, Appendix L, June 2010, pp. 214.

[520] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 43.

[commercial in confidence].[521]

Non pole distribution substation routine maintenance and overhead mounted switchgear inspection and maintenance

Consistent with its claims for other forecast costs under its ESMS, JEN proposed that these step changes are driven by a change in regulatory obligations and operating environment.[522]

JEN's justification for the non pole distribution substation routine maintenance proposal was that:

> Analysis of outages caused by plant failures within distribution substations shows that switchgear dominates.[523]

Similarly, JEN's justification for the overhead mounted switchgear inspection and maintenance proposal was that:

> This type of plant has an ongoing need for maintenance to ensure that it remains in a serviceable condition. Reliance on corrective maintenance only has been used in the past but this has resulted in operational delays and network faults. Consequently an inspection driven condition based maintenance strategy is required to ensure the availability, safety and reliability of this group of assets.[524]

The AER considers that these risks are not new and that these proposals are not being driven by a specific change in regulatory obligations or requirements. However, the AER acknowledges that JEN may be required to undertake such programs to maintain the quality, reliability and safety of supply of standard control services in the forthcoming regulatory control period. In relation to these step changes, ESV advised the AER that it:

> … does not dispute the need for this program, but considers that most of the elements are driven primarily by factors other than safety (e.g. reliability of supply) and should be justified by those other factors.[525]

The AER notes that overhead mounted switchgear inspection and maintenance step change is being driven by an aim:

> …to achieve a high level of reliability from distribution overhead line switchgear by preventive & corrective maintenance coupled with planned economic replacement of end-of-life units before failure.[526]

521 NER, clauses 6.5.6(c)(1), 6.5.6(a)(3) and 6.5.6(a)(4).
522 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 45.
523 JEN, *Revised regulatory proposal*, Appendix 11.15, confidential, p. 7.
524 JEN, *Regulatory proposal*, Appendix 11.9, confidential, p. 6.
525 ESV, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, 18 October 2010, p. 11.

The AER also notes that JEN submitted that there is no indication of a link between age or location and failure probability for overhead mounted switchgear which is why a more routine approach of identifying possible faults and maintaining switchgear should be undertaken.[527] The AER therefore agrees that the current corrective basis maintenance program should be addressed.

One option for addressing this issue would be to replace all existing air break switchgear, which is the oldest asset of this type, with newer gas insulated switchgear. However, the AER notes that JEN's proposed overhead mounted switchgear maintenance and inspection program aims to balance opex, network risk and capex through a more routine program which will achieve 'economies' by only replacing switchgear where it is found in an unsatisfactory condition by inspection.[528] Therefore, the AER considers that JEN's proposal to move from a corrective basis to a more preventative approach is prudent.

The AER notes that JEN's estimate for this proposal is based on unit rates incurred in the 2006–10 regulatory period and the number of switches and disconnectors installed on JEN's network. The AER considers these to be a reasonable estimate of the benchmark efficient costs to undertake this proposal.

Based on this the AER considers that in implementing this proposal JEN will incur costs above those in the 2006–10 regulatory period, that the substitution possibilities between opex and capex have been addressed and that the proposal reflects expenditure that would be incurred by an efficient DNSP in the forthcoming regulatory control period.[529]

Similarly, the non–pole distribution substation routine maintenance step change is aimed at:

> …achieving a high level of reliability through preventive & corrective maintenance coupled with planned economic replacement of end-of-life units before failure.[530]

JEN submitted that currently there is limited factual data on failure rates, useful life and wear out for these assets and that particular types of these assets have a history of failures and high maintenance costs.[531] Combined with a data collection program to rectify the limited data issue, the proposed routine non–pole distribution maintenance program will deliver improved life cycle management and also reliability and safety of the asset.

As particular types of assets have known failure rates and high maintenance costs there is some possibility to mitigate this risk through undertaking a replacement program. However, the AER notes that such a program would be at the expense of a routine program for the assets that are not considered in this category of assets.

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526 JEN, *Regulatory proposal*, Appendix 11.9, confidential, p. 4.
527 JEN, *Regulatory proposal*, Appendix 11.9, confidential, p. 5.
528 JEN, *Regulatory proposal*, Appendix 11.9, confidential, pp. 5–12.
529 NER, clauses 6.5.6(e)(4), (5) and (7).
530 JEN, *Regulatory proposal*, Appendix 11.15, confidential, p. 4.
531 JEN, *Regulatory proposal,* Appendix 11.15, confidential, p. 6.

Similar to the overhead mounted switchgear maintenance and inspection program, this proposal aims to balance opex, network risk and capex through a more routine program which will provide a more predictable and sustainable opex and capex approach associated with managing and maintaining these assets. Therefore the AER considers that JEN's proposal to move from a more corrective basis to a more routine approach is prudent.

The AER notes that JEN's estimate for this proposal is based the number of sites to be inspected and the contract rate per site which includes asset data collection and electrical inspection. The AER considers this to be a reasonable estimate of the benchmark efficient costs to undertake this proposal.

Based on this the AER considers that in implementing this proposal JEN will incur costs above those in the 2006–10 regulatory period, that the substitute possibilities between opex and capex have been addressed and that the proposal reflects expenditure that would be incurred by an efficient DNSP in the forthcoming regulatory control period.[532]

The AER considers that the forecast cost proposed by JEN for the overhead mounted switchgear inspection and maintenance and non–pole distribution substation routine maintenance step changes are consistent with a total forecast opex that reasonably reflects the opex criteria. This proposal will maintain the quality, reliability and security of supply of standard control services and the reliability, safety and security of the distribution system through the supply of standard control services.[533]

Broadmeadows site relocation

JEN noted that since the AER's draft decision the business case for this step change has been further developed and that this step change is linked to the Wilson Cook criteria in the New South Wales final decision.[534] However, JEN noted that internal approval is unlikely to occur until the AER approves its proposal. JEN noted that a 'double bind' will occur should the AER not approve the proposed expenditure.

The AER notes that since the submission of JEN's revised regulatory proposal, the AER has received further information on the development of the business case for this proposal.[535] The AER considers that JEN has demonstrated that it is likely that this project will be undertaken during the forthcoming regulatory control period.

Of the $2.1 million ($2010) requested by JEN for this step change, approximately $0.1 million ($2010) relates to the forecast costs to relocate staff from their existing site to their new site.[536] The AER notes that the remainder of this forecast step change relates to compensating employees for a change in their conditions of employment which is consistent with the Jemena Asset Management collective agreement.[537]

The AER considers that JEN has demonstrated that it will incur costs due to the site relocation. The relocation costs ($0.1 million) are costs that the AER considers are

[532] NER, clauses 6.5.6(e)(4), (5) and (7).
[533] NER, clauses 6.5.6(c)(1), 6.5.6(a)(3) and 6.5.6(a)(4).
[534] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 61.
[535] JEN, Response to information requested on 7 September 2010, 10 September 2010.
[536] JEN, *Broadmeadows relocation business proposal*, confidential, February 2010
[537] JEN, *Jemena asset management collective agreement (Vic) 2009*, p. 42.

reflective of the benchmark expenditure an efficient DNSP would incur for this proposal. The AER considers this is consistent with the opex factors.[538]

JEN's proposed compensation costs are primarily driven by estimates of excess time taken to travel to the new site.[539] The AER notes that these compensation costs are calculated on a daily travel time in minutes multiplied by a designated rate per minute and is calculated on a case by case basis per employee. As JEN has yet to successfully secure a new site location the exact calculations are difficult to quantify. Further, the AER acknowledges that while some of JEN's staff will be required to travel further distances due to the change in sites, other staff will be required to travel less distance and therefore will be better off. However, the AER's analysis of JEN's compensation costs demonstrates that depending on the additional length of travel time, an employee's relocation costs can vary between a range of zero and $20 000 ($ nominal). JEN's estimates are based on an average estimate based on actual opex incurred by JEN where it undertook similar relocation of sites. The AER considers this is consistent with the opex factors.[540]

Further, consistent with the AER's discussion on the Broadmeadows relocation capital expenditure forecasts (see chapter 8); the AER considers that while there are likely to be delays to JEN's timeline for this proposal these are likely to only be minor. Therefore, the AER has not adjusted JEN's opex forecast in relation to these delays.

For the reasons discussed above and having regard to a benchmark opex that would be incurred and the actual opex incurred during preceding regulatory periods as part of factors 4 and 5 of the opex factors, the AER considers that JEN's proposal is consistent with a total forecast opex that reasonably reflects the opex criteria.

Distribution substation cleaning, gardening and security

The AER notes that page 8 of appendix 7.2 of JEN's revised regulatory proposal shows the 'JEN revised regulatory proposal' figure as zero in the step changes summary table.[541] Despite this, the AER is responding to this step change based on the discussion on pages 43 and 44 of the same appendix, which does not agree with the AER's draft decision. The AER further notes that table 4-5 on page 44 of appendix 7.2 appears to mistakenly refer to overhead mounted switchgear inspection and maintenance.[542]

JEN considered that this step change is indirectly triggered by JEN's changed regulatory obligations following amendments to the Electricity Safety Act and subordinate regulations, in particular a requirement to minimise 'as far as practicable' the bushfire danger arising from its network. JEN considers this requirement warrants routine grounds maintenance rather than corrective grounds maintenance. JEN further considered the only opex allowance it has received to allow it to meet its obligations under the Occupational Health and Safety Act 2004 is for asbestos related work, and

538 NER, clause 6.5.6(e)(4).
539 JEN, *Jemena asset management collective agreement (Vic) 2009*, p. 42.
540 NER, clause 6.5.6(e)(5).
541 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p.8.
542 ibid, pp. 43–44.

not for the type of routine cleaning and maintenance contemplated by this step change.[543]

The AER notes that JEN is proposing to shift to maintenance of grounds on a routine basis rather than a corrective basis to minimise ‘as far as practicable’ the bushfire danger arising from its network. The AER agrees with JEN that a more routine approach in managing the risks of bushfire danger is a prudent activity to undertake in the forthcoming regulatory control period, and is satisfied that this meets the requirements of clause 6.5.6(c)(2) of the NER. The AER is also conscious of the regulations that JEN has linked this proposal to, and has examined JEN’s life cycle management plan for grounds and housing of zone substations and non-pole type distribution substations.[544]

The AER notes that based on this life cycle management plan, JEN has proposed to apply the routine maintenance program to its distribution substations that it currently employs for its zone substations. JEN notes that the current zone substation maintenance program has resulted in well maintained grounds.[545]

The AER considers that JEN has demonstrated that this step change is prudent, and incremental to the current base year allowance. Consequently the AER considers that this proposal will result in a total forecast opex that reasonably reflects the costs that a prudent operator in JEN’s circumstances would require to maintain the reliability, safety and security of the distribution system.[546]

L.5.13.6 AER conclusion

For the reasons set out above, the AER considers that the following step changes are consistent with a total forecast opex that reasonably reflects the opex criteria: [547]

- neutral condition monitors
- non–pole distribution substation routine maintenance and overhead mounted switchgear inspection and maintenance
- [confidential]
- Broadmeadows site relocation.
- distribution substation cleaning, gardening and security.

543 ibid. p. 44.
544 JEN, *Revised regulatory proposal– Grounds and housing of zone substations and non-pole type distribution substations life cycle management plan (JEN 4356-120)*, July 2009.
545 ibid., p. 5.
546 NER, cll. 6.5.6(c)(2), 6.5.6(a)(4).
547 NER, cll. 6.5.6 (a), 6.5.6(c).

Table L.54 AER final decision for additional step changes proposed by JEN ($'000, 2010)

Step change	2011	2012	2013	2014	2015
Sunshine depot restoration	25.3	–	–	–	–
Neutral condition monitors	303.8	303.8	303.8	303.8	303.8
Non–pole distribution substation routine maintenance	101.3	101.3	101.3	101.3	101.3
Overhead mounted switchgear inspection and maintenance	181.3	190.4	199.5	208.6	218.7
[confidential]	–	7.6	15.2	25.3	25.3
Broadmeadows	2 126.5	–	–	–	–
Distribution substation cleaning, gardening and security	181.3	190.4	199.5	208.6	218.7
Total	**2919.4**	**793.4**	**819.2**	**847.5**	**867.8**

Source: AER analysis.

L.5.14 Expenditure to achieve capex/opex balance

L.5.14.1 AER draft decision

JEN's initial regulatory proposal included a suite of step changes relating to expenditure to achieve capex/opex balance. Two of these step changes—zone substation power quality metering maintenance and secondary spares maintenance—were also proposed by United Energy. The AER did not accept these step changes in its draft decision.[548]

The AER noted in the draft decision that, with the exception of the power quality metering maintenance and secondary spares maintenance step changes, these proposed step changes may have merit and are reasonably well defined. However, the AER considered that the proposed step changes were being driven by economic benefits rather than a regulatory obligation, or a change in the operating environment for JEN.[549]

The AER rejected secondary spares maintenance on the basis that JEN and United Energy were unable to clearly state the benefits of the proposed expenditure other than to note that a failure to implement the practice increases the risk that the spare equipment will not be serviceable when required.[550]

The AER rejected power quality metering maintenance due to insufficient information regarding when the meters were initially installed.[551]

548 AER, *Victorian draft decision*, Appendix L, pp. 219–222, 237–239.
549 ibid., pp. 220–222.
550 ibid., pp. 221–222, 238.
551 ibid., p. 221, p. 239.

L.5.14.2 Victorian DNSP revised regulatory proposals

JEN considered that the proposed step changes arise from a change in its operating environment, and reasonably reflect the opex criteria, having regard to factor (7) in particular (the substitution possibilities between capex and opex). JEN therefore did not agree with the AER's draft decision.[552] JEN further stated that its forecast opex for this suite of step changes reasonably reflects the efficient costs of a prudent operator in JEN's circumstances.[553] JEN provided the AER with additional information to support its claims, including that aging assets are a significant factor in driving the proposed opex increases.[554] JEN also provided:[555]

- failure rate information for feeder and ACR outages
- feeder or ACR faults due to underground asset failure
- discounted cash flow (DCF) analysis for secondary spares maintenance.

In line with its initial regulatory proposal, JEN proposed opex step changes for:

- zone substation transient earth voltage (TEV) testing—forecast $50 600 ($2010)
- zone substation post current/voltage transformer (CT/VT) testing—forecast $24 400 ($2010)
- zone substation transformer dryouts (Trojan)—forecast $55 700 ($2010)
- zone substation degree of polymerisation (DP) testing—forecast $0.2 million ($2010)
- zone substation transformer condition testing—forecast $0.2 million ($2010)
- zone substation power quality metering maintenance—forecast $50 600 ($2010)
- zone substation secondary spares maintenance—forecast $10 100 ($2010)
- cable testing to predict/manage forecast failure increases—forecast $0.2 million ($2010).

United Energy stated that the zone substation power quality metering maintenance step change was proposed because it was not included in the scope of outsourced work that was tendered or part of United Energy's in-house expenditure forecast. United Energy further noted that other DNSPs have received operating expenditure allowances for such activities.[556] United Energy did not provide any new information in relation to secondary spares maintenance, instead referring the AER to its initial

552 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 52–61.
553 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 54.
554 ibid.
555 JEN, *Revised regulatory proposal*, Appendix A, pp. 55–56.
556 United Energy, *Revised regulatory proposal*, p. 92; Response to information requested on 22 January 2010, 22 February 2010.

regulatory proposal.[557] United Energy proposed $85 000 ($2010) for power quality metering maintenance and $10 000 ($2010) for secondary spares maintenance, in line with its initial regulatory proposal.

In relation to power quality metering maintenance, JEN and United Energy both stated that they have never been given funding for maintenance of power quality meters. The 2001–05 EDPR allowed for capex funding to install the assets, but no opex has ever been allowed. When these assets were newer, maintenance was not necessary, but as they begin to age, maintenance becomes necessary in order to maintain the reliability, safety and security of the distribution system.[558] JEN further noted that it has carried out reactive maintenance on a number of meters, but this step change is for the incremental costs of introducing a planned maintenance program.[559] The information provided by United Energy to support its power quality metering maintenance step change reflects that provided by JEN.[560]

L.5.14.3 Consultant review

Nuttall Consulting considered that, consistent with its review of JEN's initial proposal, JEN had not provided adequate information to support the proposed increases associated with the secondary spares maintenance program (despite the inclusion of a discounted cash flow analysis).[561] Nuttall Consulting also considered that United Energy had not provided sufficient information to support its secondary spares maintenance program.[562]

However, Nuttall Consulting recommended that the power quality metering maintenance program for United Energy be allowed.[563] Nuttall Consulting considered that the eight year period identified by United Energy is within industry standards and since the power quality meter assets are relatively new, maintenance will first occur in and be ongoing from the next regulatory control period.[564] Nuttall Consulting considered the proposed amount is reasonable on the basis that the meters have been installed in every United Energy zone substation and at the far end of a distribution feeder from each zone substation, and acknowledged that travel time to each meter location would be a factor in the proposed costs.[565] However, Nuttall Consulting also observed that the AER's scale escalation opex may already account for this proposed increase.[566]

Nuttall Consulting considered that since the power quality metering maintenance programs for JEN and United Energy are intended for the same purpose, consistent

557 ibid. p. 90.
558 JEN, *Revised regulatory proposal*, Appendix 7.2., p. 56; United Energy, Response to information requested on 22 January 2010, 22 February 2010.
559 JEN, *Revised regulatory proposal*, Appendix 7.2., p. 56.
560 United Energy, Response to information requested on 22 January 2010, 22 February 2010.
561 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 241.
562 ibid., pp. 281–284.
563 ibid.
564 ibid.
565 ibid.
566 ibid.

treatment justified a recommendation of JEN's secondary spares maintenance as well.[567]

With regard to the other programs, Nuttall Consulting considered that JEN's revised proposal did not address the information gaps identified in the previous Nuttall Consulting report. In addition, Nuttall Consulting identified from information in JEN's RIN that the average age of JEN's network is gradually increasing, and this has been a recognised concern of JEN (and previously AGLE) for the last decade.[568] Nuttall Consulting considered that the proposed step changes are not justified given the absence of economic analysis (apart from the DCF analysis for secondary spares maintenance) that clearly demonstrates the need for step increases in the context of existing incentive mechanisms.[569]

L.5.14.4 Issues and AER considerations

The AER accepts based on the additional information provided that JEN and United Energy have sufficiently justified the driver for power quality metering maintenance expenditure. The fact that they have not been provided with a maintenance allowance since the meters were installed suggests this expenditure is additional to their base year allowance. The AER is also satisfied based on Nuttall Consulting's advice that the proposed amounts are reasonable.

The AER is therefore satisfied that the expenditure for JEN's and United Energy's power quality metering maintenance programs forms part of a total forecast opex that that reasonably reflects the opex criteria, in particular the efficient costs that a prudent operator in the circumstances of JEN and United Energy would require to maintain the reliability, safety and security of the distribution system.[570]

In the draft decision the AER raised concerns that JEN and United Energy had not sufficiently supported the proposal for secondary spares maintenance. In its revised proposal, JEN responded to these concerns, so the AER is now satisfied that JEN has justified the need for this expenditure. In particular, the AER notes that JEN has clarified the change in operating circumstances that have resulted from the introduction of digital microprocessors, and the risks associated with the lack of maintenance.[571] United Energy has also provided information to that effect in response to an information request.[572] The AER is therefore satisfied that the secondary spares maintenance programs for JEN and United Energy forms part of a total forecast operating expenditure that reasonably reflects the opex criteria, in particular the costs that a prudent operator in JEN's or United Energy's circumstances would require to maintain the quality, reliability and security of supply.[573]

For the other capex/opex balance step changes (TEV testing, CT/VT testing, transformer dryouts, DP testing, transformer condition testing and cable testing), the AER notes Nuttall Consulting's concerns, but has reconsidered its position in light of the additional information provided by JEN.

[567] ibid., pp. 244–245
[568] ibid., pp. 241–244.
[569] ibid..
[570] NER, cll. 6.5.6(c)(1),(2), 6.5.6(a)(3).
[571] JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 57.
[572] United Energy, Response to information requested on 22 January 2010, 22 February 2010.
[573] NER, cll. 6.5.6(c)(2); 6.5.6(a)(3).

Although the AER does not agree that this expenditure is necessarily required as a result of a change to JEN's operating environment, the AER considers that there is merit in these proposals. Having regard to clause 6.5.6(e)(7) of the NER, a prudent operator should test and maintain its equipment if it results in capex savings. The AER notes that JEN has not explicitly quantified the capex savings as a result of these programs, but acknowledges the substitution possibilities between capex and opex. In the context of the AER's reductions to JEN's forecast capex allowance, the AER considers that this expenditure is justified and forms part of a total forecast operating expenditure that reasonably reflects the opex criteria, in particular the costs that a prudent operator in JEN's circumstances would require to maintain the quality, reliability and security of supply.[574]

L.5.14.5 AER conclusion

For the reasons discussed above, the AER accepts all capex/opex trade-off step changes except for power quality metering maintenance. The AER considers $0.8 million as proposed by JEN and $95 000 as proposed by United Energy forms part of a total forecast opex that reasonably reflects the opex criteria.

Table L.55 AER final decision for capex/opex balance step changes proposed by United Energy ($'000, 2010)

Step change	2011	2012	2013	2014	2015	Total
ZS power quality metering maintenance	47.0	38.0	–	–	–	**85.0**
ZS secondary spares maintenance	–	10.0	–	–	–	**10.0**
Total	**47.0**	**48.0**	**–**	**–**	**–**	**95.0**

Source: AER analysis.

574 NER, clauses 6.5.6(c)(2); 6.5.6(a)(3).

Table L.56 AER final decision for capex/opex balance step changes proposed by JEN ($'000, 2010)

Step change	2011	2012	2013	2014	2015	Total
ZS TEV testing	10.1	10.1	10.1	10.1	10.1	**50.6**
ZS pot VT/CT testing	1.6	6.1	8.4	4.9	3.4	**24.4**
ZS transformer dryouts (Trojan)	11.1	11.1	11.1	11.1	11.1	**55.7**
DP testing	32.9	34.2	35.8	37.3	38.6	**178.8**
ZS transformer condition testing	40.5	50.6	40.5	40.5	40.5	**212.6**
ZS power quality metering maintenance	32.4	–	–	–	18.2	**50.6**
ZS secondary spares maintenance	10.1	–	–	–	–	**10.1**
Cable testing	34.9	37.7	40.7	43.8	47.1	**204.2**
Total	**173.8**	**149.9**	**146.7**	**147.7**	**169.1**	**787.2**

Source: AER analysis.

L.5.15 Information technology opex step changes

L.5.15.1 AER draft decision

The AER considered four categories of IT step changes proposed by JEN:

- increased support of current systems
- introduction of new systems
- systems replacement
- new data facilities.[575]

The AER was not satisfied that the proposed step change for increased support of current systems demonstrated that these costs represented an increase in the replacement of existing systems or support costs.[576]

Similarly, the AER was not satisfied that the proposed step change for the introduction of new systems demonstrated that this additional expenditure was driven by a new regulatory obligation or a change in operating environment.[577]

The AER was satisfied that the proposed step change for systems replacement and the new data centre facilities categories demonstrated that these step changes were

575 AER, *Victorian draft decision,* Appendix L, pp. 223–227.
576 AER, *Victorian draft decision,* Appendix L, p. 226.
577 AER, *Victorian draft decision,* Appendix L, p. 226.

required by a change in the operating environment and that the proposed expenditure reasonably reflected the efficient costs of a prudent DNSP.[578]

In addition to the four categories of IT step changes, the AER also considered and accepted JEN's proposal of a reduction in expenditure due to IT efficiency gains from improved IT staff productivity.[579]

L.5.15.2 Victorian DNSP revised regulatory proposals

JEN did not accept the AER's draft decision for three of the four step changes relating to the increased support of current systems category.[580] JEN accepted the AER's position to not support the program and portfolio management proposal as a step change.[581] However, JEN contended that the SAS replacement, BRIO query replacement and asset defects database proposals were changes in the operating environment and therefore should be provided for as step changes.[582] JEN noted that there are currently no maintenance costs for these systems as they have been either developed internally or the vendors offer no support due to their age. Further, JEN noted that these systems need to be replaced and will then incur additional maintenance costs. JEN also noted that these step changes will improve its capacity to operate efficiently. JEN proposed $0.5 million ($, 2010) for these step changes and that these step changes are linked to the Wilson Cook criteria in the New South Wales final decision as well as meeting the opex objectives, in particular clauses 6.5.6(a)(1), (3) and (4) of the NER.

JEN accepted the AER's draft decision for six of the seven step changes relating to the introduction of new systems category.[583] JEN agreed with the AER's position to not support the following proposals as step changes:

- real time security implementation
- spatial intelligence tool
- distribution management system
- relay equipment setting information system (RESIS)
- equipment testing recording and verification
- service delivery and field mobile computing.[584]

However, JEN contended that the emergency risk and safety management proposal is a change in the operating environment and therefore should be provided for as a step change.[585] JEN noted that this step change is linked to the Wilson Cook criteria in the New South Wales final decision. JEN further noted that while it accepted the AER's

578 AER, *Victorian draft decision*, Appendix L, pp. 226–227.
579 AER, *Victorian draft decision*, Appendix L, p. 227.
580 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 9–10, 66–68.
581 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 10.
582 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 66–68.
583 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 9–10, 65–66.
584 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 9–10.
585 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 65–66.

draft decision on climate change (where the costs were considered to be in the base level opex), it considered that the emergency, risk and safety management proposal is a new system and therefore not in the base level opex. JEN noted that the need for this proposal became apparent after the April 2008 storm and 2009 heatwave. Further, JEN noted that this proposal is in line with the Victorian Government's recommendations to improve the use of technology for emergency response and management capabilities. Based on this, JEN considered that the timing is now 'prudent' to implement this system. JEN proposed $0.5 million ($2010) for this step change.

JEN accepted the AER's draft decision for the step changes relating to the systems replacement and the new data centre facilities categories.[586] JEN, however, revised the proposed amounts and noted that the expenditure forecast for new data centre facilities reflected more up to date information.[587]

L.5.15.3 Consultant review

Nuttall Consulting considered that JEN's revised regulatory proposal did not contain any new or additional information to support its proposed support system step change proposals.[588] Nuttall Consulting considered that while the information put forward by JEN in support of the SAS replacement, BRIO query replacement and asset defects database step changes are overall factually correct, JEN's lack of reference to the overall IT environment is misleading. Specifically, Nuttall Consulting noted the difference between direct support costs and the overall costs of unsupported or aging systems and stated that:

> To separate and indentify only the systems and tools that are moving from low or no-cost to a higher level of support would be biased. A balanced approach would require consideration of all systems and their changing level of support.[589]

On this basis, Nuttall Consulting did not recommend the proposed step change costs for the SAS replacement, BRIO query replacement and asset defects database.

Nuttall Consulting noted that it was unable to recommend JEN's emergency risk and safety management step change because it was closely linked to the extreme events forecast by AECOM and that the AER had not accepted the AECOM estimates of the cost impact of climate change in its draft decision.[590] Nuttall Consulting further noted that JEN's revised regulatory proposal agreed with the AER's draft decision on climate change, which considered that the number of extreme weather forecasts is not likely to be greater in 2015 than in 2009. Based on this, Nuttall Consulting considered that as extreme weather forecasts are not likely to increase over the regulatory period then the costs of meeting its obligations should already be included in JEN's current expenditures.

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586 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 9–10, 68–70.

587 JEN, *Revised regulatory proposal,* Appendix 7.2, confidential, pp. 68–70.

588 Nuttall Consulting. *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 236–239.

589 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 239.

590 Nuttall Consulting. *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 235–236.

Nuttall Consulting further noted that JEN’s revised regulatory proposal linked this step change to the

> …state government recommendations to improve the use of technology for emergency response and management capabilities.[591]

However, Nuttall Consulting noted that JEN has not referred this step change to opex objective clause 6.5.6(a)(2) of the NER which relates to a changed regulatory obligation or requirement. Based on this Nuttall Consulting considered that this step change was not proposed to meet a new or changed regulatory obligation or requirement.

Nuttall Consulting further reviewed JEN’s revised regulatory proposal for production data centre and disaster recovery centre step changes.[592] Nuttall Consulting noted it had recommended this proposal in JEN’s initial regulatory proposal. Nuttall Consulting further noted that JEN’s revised regulatory proposal updated these costs due to more up to date information including a more precise commencement date for the operation of the disaster centre. Nuttall Consulting recommended this proposal and recommended the costs as proposed in JEN’s revised regulatory proposal.

L.5.15.4 Issues and AER considerations

The AER acknowledges Nuttall Consulting’s statement that JEN has not had regard to the overall IT environment in proposing its increased support system step changes. However, in relation to JEN’s actual overall IT expenditure for the 2006–10 regulatory period the AER considers that from the information available there are no support costs in this expenditure relating to the SAS and BRIO query systems. The AER also considers that there are no dedicated resources that formally support the asset defects data base system in the 2006–10 regulatory period. This is supported by Nuttall Consulting who note that:

> Nuttall Consulting considers that the information put forward by Jemena is factually correct for the three systems that have been identified…[593]

While the AER notes that JEN has not provided any material supporting information in its revised regulatory proposal, the AER has revisited JEN’s initial regulatory proposal and supporting information and considers that additional costs for these proposals will be incurred due to these IT proposals in the forthcoming regulatory control period. Therefore the AER considers allowances should be made in JEN’s forecast opex.

The AER further considers that JEN’s proposed costs are consistent with costs that would be incurred by the benchmark efficient DNSP over the forthcoming regulatory control period for these proposals.[594]

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[591] JEN, *Revised regulatory proposal,* Appendix 7.2, confidential, p. 66 , cited in Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 235.

[592] Nuttall Consulting. *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 239–240.

[593] Nuttall Consulting. *Victorian electricity distribution revenue review: Revised proposals,* 22 October 2010, p. 238.

[594] NER, clause 6.5.6(e)(4).

Based on this, with regard to the actual expenditure incurred in the 2006–10 regulatory period and the benchmark opex that would be incurred by the efficient DNSP in the forthcoming regulatory control period, the AER considers that the forecast costs proposed by JEN for the SAS replacement, BRIO query replacement and asset defects database proposals are consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria.[595]

With respect to the emergency risk and safety management step change, the AER agrees with Nuttall Consulting that as the number of extreme events is not likely to be greater in 2015 than in 2009 then the costs of meeting JEN's obligations in this regard should be included in its base year expenditure. JEN linked this proposal to opex objective clauses 6.5.6(a)(1) which refers to 'meet' or 'manage' expected demand of standard control services over the forthcoming regulatory control period. The AER considers that as the number of extreme events is not considered to be increasing then the base year expenditure provides the appropriate costs to meet or manage this demand over the forthcoming regulatory control period.

The AER also notes that JEN has proposed this step change:

> …to improve JEN's emergency response management.[596]

JEN claimed that customers will benefit from this proposal as it will bring an improvement to reliability and safety of supply and further linked this proposal to opex objective clauses 6.5.6(a)(3) and (4). However, the AER notes that these opex objectives refer to 'maintain' and not improve reliability and safety. Therefore, the AER considers that this proposal goes beyond these opex objectives and therefore does not represent the efficient costs of a DNSP in JEN's circumstances.

Further, the AER notes that any improvements in reliability of supply would provide greater rewards under the STPIS and therefore would be self financing if efficient. However, the AER notes that JEN has not provided any cost benefit analysis for this step change nor has it defined the savings and benefits for this proposal and the expected time of their realisation.

Based on the discussion above, with regard to the actual expenditure incurred in the 2006–10 regulatory period, the AER considers that to provide an allowance for this step change to maintain the quality, reliability and security of supply of standard control services and the reliability, safety and security of the distribution system through the supply of standard control services would not be consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria.[597]

The AER notes that it accepted JEN's new data centre facilities step change in its draft decision.[598] JEN, in its revised regulatory proposal, revised its production data centre step changes for actual expenditure in 2009. JEN also revised its disaster

595 NER, clauses 6.5.6(e)(4) and (5); 6.5.6(c).
596 JEN, *Revised regulatory proposal, Appendix 7.2, confidential*, p. 66.
597 NER, clauses 6.5.6(e)(5); 6.5.6(c); 6.5.6(a)(3) and 6.5.6(a)(4).
598 AER, *Victorian draft decision*, Appendix L, June 2010, pp. 227–230.

recovery centre step changes to account for the delay in commencement of six months.[599] The AER is satisfied that these revised opex forecasts are reasonable.

With respect to the AER's draft decision to accept JEN's IT efficiency gain step change, the AER agrees with JEN's revised regulatory proposal that the acceptance of this step change combined with the rejection of the JEN's IT scale escalator creates a situation where JEN incurs a double deduction for IT efficiency.[600] As discussed in the scale escalation appendix (appendix J), the AER has not accepted JEN's IT scale escalator, but to avoid imposing a double deduction on JEN for IT efficiency, the AER has also not accepted JEN's IT efficiency step change proposal.

L.5.15.5 AER conclusion

For the reasons set out above and having regard to the benchmark firm and the actual costs incurred in the 2006–10 regulatory period as part factors 4 and 5 of the opex factors, the AER considers that the following step changes would not be consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria:

- emergency risk and safety management
- IT efficiency gain step change.[601]

For the reasons set out above and having regard to the benchmark firm and the actual costs incurred in the 2006–10 regulatory period as part factors 4 and 5 of the opex factors, the AER considers that the following step changes are consistent with a total forecast operating expenditure that reasonably reflects the operating expenditure criteria:

- SAS replacement
- BRIO query replacement
- asset defects database
- new data centre facilities.[602]

599 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 69.
600 JEN, *Revised regulatory proposal*, p. 121.
601 NER, clauses 6.5.6 (a); 6.5.6(c).
602 NER, clauses 6.5.6 (a); 6.5.6(c).

Table L.57 AER final decision for IT step changes proposed by JEN ($'000, 2010)

Step change	2011	2012	2013	2014	2015
SAP replacement	–	–	–268.9	–268.9	–268.9
SAS replacement	20.8	20.8	20.8	20.8	20.8
BRIO query replacement	33.0	33.0	33.0	33.0	33.0
Asset defects database	40.0	40.0	40.0	40.0	40.0
New data centre facilities	414.0	771.1	886.6	1 002.0	1 117.4
Total	507.8	864.9	711.5	826.9	942.3

Source: AER analysis.

L.5.15.6 JEN late, additional proposed step changes

AER draft decision

The AER assessed four step changes that JEN claimed were included in its total forecast expenditure for step changes but for which specific details regarding the changes were not included in its regulatory proposal.[603] The AER considered that these late, additional step changes were not step changes because:

- JEN withdrew the avoided cost distribution payment to AGLPG because it would not occur in the forthcoming regulatory control period
- the base year efficiency carryover proposal was related to the efficiency carryover mechanism, was discussed in the base opex section and was not a step change
- JEN had not demonstrated that the two stakeholder relations proposals were directly related to a specific regulatory trigger or a change in the operating environment.[604]

Victorian DNSP revised regulatory proposals

JEN agreed that the base year efficiency carryover proposal was not a step change. JEN also agreed with the AER's draft decision to not provide a step change for additional staff to manage claims, one of its stakeholder relations step changes.[605] However, JEN did not agree with the AER's draft decision on its proposed step change for marketing communications, its other stakeholder relations step change.[606]

Issues and AER considerations

The AER's discussion on JEN's revised regulatory proposal for stakeholder relations—marketing communications is discussed above regarding marketing communications in section L.5.6.3.

[603] AER, *Victorian draft decision,* Appendix L, pp. 227–230.
[604] AER, *Victorian draft decision,* Appendix L, pp. 227–230.
[605] JEN, *Revised regulatory proposal, Appendix 7.2, confidential*, pp. 9–10.
[606] JEN, *Revised regulatory proposal, Appendix 7.2, confidential*, pp. 9, 62–65.

L.5.16 Additional step changes proposed by SP AusNet

The AER did not accept in the draft decision any of the additional step changes proposed by SP AusNet in its initial regulatory proposal. SP AusNet did not agree with the AER's draft decision and included step changes in its revised regulatory proposal for:

- national energy customer framework
- power cable test program
- condition monitoring
- power transformer refurbishment
- substation earthing systems
- substation site cleanup
- substation civil infrastructure works
- substation fire systems
- process and configuration management
- PSAIDI reduction
- leasing of fleet and major facilities
- incremental vegetation growth.

SP AusNet also included two step changes in its revised regulatory proposal that it did not included in its initial proposal:

1. conductor tie replacement
2. enhanced asset inspection programs.

L.5.16.1 National energy customer framework

SP AusNet's revised regulatory proposal sought $0.3 million ($2010) and advised that, consistent with its initial regulatory proposal, the primary driver for this step change related to:

> …the development and finalisation of the transitional arrangements in support of the NECF, not the NECF itself.[607]

SP AusNet concurred with the AER that contributing to regulatory forums was standard business practice.

[607] SP AusNet, *Revised regulatory proposal*, p. 218.

However it considered that NECF regulatory changes and significant transitional arrangements measures were non-recurrent activities and that without step change funding, SP AusNet would not be able to recover its efficient operating costs.

SP AusNet submitted that if the AER rejected its proposed expenditure, it would require additional resources over the forthcoming regulatory control period to ensure it could recover unknown non-recurrent future regulatory costs.[608]

The AER notes the considerable number of regulatory forums and consultations that network providers and stakeholders engage in throughout a regulatory control period. In recent years these have included, among others, the national stakeholder steering committee for a national smart meter rollout and retailer of last resort arrangements, together with NECF deliberations.

Where Victorian DNSPs engage with regulators and policy makers on matters pertaining to their activities, the AER considers these will be reflected in base opex and reflect ordinary business operations.

SP AusNet's initial and revised regulatory proposals with respect to the NECF package did not state the 'transitional arrangements' it would be subject to, or how they would impact its operations.

The AER notes that no other Victorian DNSP sought step change costs associated with participation in regulatory forums generally, or for the NECF in particular.

The AER is unable to determine the transitional measures SP AusNet will be required to meet, if any. Additionally, it is not certain that the final obligations imposed through the NECF will represent a fundamental shift in obligations on the Victorian DNSPs from those which already apply.

Consequently the AER is not satisfied that the opex proposed by SP AusNet reasonably reflects the efficient costs that a prudent operator requires to meet it regulatory obligations.

For the reasons discussed and as a result of the AER's consideration of SP AusNet's revised regulatory proposal and other supporting information the AER is not satisfied that SP AusNet's proposed national energy customer framework step change reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

L.5.16.2 Power cable test program

AER draft decision

The AER considered that the power test cable program was not a step change because SP AusNet did not demonstrate that it was linked to a new or changed regulatory obligation or requirement and did not represent efficient costs required to achieve the opex objectives.[609]

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[608] SP AusNet, *Revised regulatory proposal*, p. 218.
[609] AER, *Draft decision*, Appendices, p. 234.

Victorian DNSP revised regulatory proposals

SP AusNet stated that the AER did not detail its reasons for rejecting this proposed step change in the draft decision. SP AusNet reiterated its position in its initial proposal that the power cable test program was justified because:

- of the increasing failure rate of underground power cables
- SP AusNet has already purchased equipment to undertake these tests, showing its commitment to the program
- it will lead to more efficient management of assets in the long term.[610]

SP AusNet considered that an assessment of the benefits of this program exceeded the costs even under conservative assumptions.[611]

Consultant review

The SP AusNet asset management strategy indicates a relatively young population of assets and there is no indication that significant volumes of assets are approaching the end of their technical lives. Nuttall Consulting also noted that while failure rates per kilometre are increasing, it is not at a rate much greater than that of the overall population increases.[612]

Regarding SP AusNet's NPV analysis, Nuttall Consulting stated that it was difficult to understand how the $1.65 million program can result in a positive NPV noting that SP AusNet has only 1439 km of installed power cables with 0.5 per cent or less being older than 40 years. SP AusNet did not provide the inputs to the analysis and it was unclear whether the cost of de-energisation had been considered in the analysis.[613]

SP AusNet stated that it had already purchased equipment to undertake the tests. Nuttall Consulting noted that SP AusNet did not indicate the dates this equipment was purchased or whether any tests have been undertaken to date. SP AusNet did not provide any business case or cost analysis that justified this purchasing decision.[614]

For the above reasons Nuttall Consulting was unable to determine whether the proposed expenditure was either efficient or prudent and did not recommend that the proposed expenditure be allowed for recovery in the forthcoming regulatory control period.[615]

Issues and AER considerations

The AER has considered SP AusNet's initial and revised regulatory proposals and accompanying information and considers that the issues outlined by Nuttall

610 SP AusNet, *Revised regulatory proposal*, p. 219.
611 SP AusNet, *Revised regulatory proposal*, pp. 220–221.
612 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 262.
613 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 263.
614 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 263.
615 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 263.

Consulting raise concerns regarding the robustness of the inputs used in the NPV analysis. For example, Nuttall Consulting noted that SP AusNet has a relatively young cable network.[616] The majority of SP AusNet's installed cables have an expected technical life of 45 years. SP AusNet stated that the average age of its cables is 16 years with most less than 20 years of age. As a result only 0.013% per annum (or approximately 200m per annum) of the fleet will reach the end of their technical lives in the forthcoming regulatory control period.[617] Nuttall Consulting also considered SP AusNet's identification that the rate of failures is increasing because while failure rates per kilometre are increasing, it is not at a rate much greater than that of the overall population increases.[618]

The AER notes that the NPV of the costs of the power cable test program was hard-coded in SP AusNet's spreadsheets and SP AusNet did not provide any information regarding the assumptions behind the numbers. It is therefore difficult for the AER to assess the prudency or efficiency of the proposed opex for the power cable test program. It is also unclear whether or not the costs adopted by SP AusNet do not include the cost of de-energisation, which was noted by Nuttall Consulting. If SP AusNet's analysis does not include the cost of de-energisation, then the NPV costs of the program would rise with its inclusion.

SP AusNet stated that it had already purchased equipment to undertake the tests.[619] Nuttall Consulting noted that SP AusNet did not indicate the dates this equipment was purchased or whether any tests have been undertaken to date. SP AusNet did not provide any business case or cost benefit analysis that justified this purchasing decision.[620] SP AusNet subsequently also provided the AER with information relating to the purchase of the equipment and the tests carried out by SP AusNet in the current regulatory period.[621] SP AusNet appears to have begun its power cable test program in late 2008 with at least 44 cables having been tested with the purchased equipment since that time. SP AusNet also provided 'a typical cable test report' dating to December 2008.[622] This suggests that the power cable test program has been a regular part of SP AusNet's opex program in the current regulatory period and would be captured in the base year opex.

Having had regard to SP AusNet's initial and revised proposals and analysis done by and for the AER, the AER is not satisfied that the proposed expenditure for the power cable test program reasonably reflects the requirements of clauses 6.5.6(c)(1) and (2) of the NER.[623] The AER therefore does not consider that the proposed step change is consistent with clause 6.5.6(c)(2).

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616 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 262.
617 SP AusNet, *Power cables and process and configuration*, 28 September 2010, p. 1.
618 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 262.
619 SP AusNet, *Revised regulatory proposal*, p. 219.
620 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 263.
621 SP AusNet, Response to information requested on 24 September, 28 September 2010.
622 SP AusNet, *Power cables and process and configuration*, 28 September 2010, p. 3.
623 Clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(3) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(5) of the NER.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of SP AusNet's revised regulatory proposal and other supporting information, the AER considers that the proposed amount of $1.68 million ($2010) is not consistent with a total forecast opex that reasonably reflects the opex criteria. In coming to this view the AER has had regard to the opex factors.[624]

L.5.16.3 Condition monitoring

AER draft decision

The AER considered that the condition monitoring program was not a step change because SP AusNet did not demonstrate that it was linked to a new or changed regulatory obligation or requirement and did not represent efficient costs required to achieve the opex objectives.[625]

The AER agreed with Nuttall Consulting who stated that SP AusNet had not demonstrated the quantitative benefits associated with the project, nor had SP AusNet demonstrated that the project was prudent and efficient. The AER also considered that business process improvements which result in lower costs will be self financing as the net costs should be less than those reflected in the revenue requirement.[626]

In having regard to benchmark opex that would be incurred by an efficient DNSP, the AER noted that no other Victorian DNSP has sought this type of step change for the forthcoming regulatory control period.[627]

Victorian DNSP revised regulatory proposals

SP AusNet considered that the AER's rationale for rejecting this step change was flawed because the conditioning monitoring program would enable SP AusNet to have a better understanding of its assets, which would lead to better informed decisions, for example, regarding capex deferrals. SP AusNet also stated that the AER's proposition that the condition monitoring program is self financing was inconsistent with the current regulatory regime.[628]

SP AusNet stated that the AER would need to thoroughly understand current expenditure on condition monitoring that is included in the base year and the extent to which each business would benefit from such a program to effectively consider condition monitoring under clause 6.5.6(e)(4) of the NER.[629]

SP AusNet argued that the benefits of the program exceeded the costs even under conservative assumptions. The analysis was combined with the power transformer refurbishment program because both programs work in unison to deliver benefits.[630]

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624 Specifically opex factors (1), (3) and (5).
625 AER, *Draft decision*. Appendix L, p. 234.
626 AER, *Draft decision*. Appendix L, p. 236.
627 NER, clause 6.5.6(e)(4); AER, *Draft decision*. Appendix L, pp. 236–237.
628 SP AusNet, *Revised regulatory proposal*, p. 222.
629 SP AusNet, *Revised regulatory proposal*, pp. 222–223.
630 SP AusNet, *Revised regulatory proposal*, pp. 223–225.

Consultant review

Nuttall Consulting raised concerns with areas of SP AusNet's NPV analysis of the condition monitoring program. Specifically, it noted that:

- costs are not treated consistently between periods
- the present value treatment of costs is not consistent
- based on current age and replacement profiles, the proposed condition monitoring (and transformer refurbishment) strategies would deliver less efficient outcomes than current practice.[631]

Despite SP AusNet's statement that the analysis was conservative, Nuttall Consulting considered that the issues with the analysis are significant enough to outweigh the potential conservatism. Nuttall Consulting considered that the analysis did not support the allowance of this proposed expenditure.[632]

Issues and AER considerations

Having had regard to SP AusNet's initial and revised regulatory proposals, the AER has concerns with the NPV analysis performed by SP AusNet to justify the condition monitoring program. The AER considers that the issues with SP AusNet's analysis as raised by Nuttall Consulting are significant enough to outweigh its potential conservatism. For example Nuttall Consulting noted that the costs for the condition monitoring program only occur in the forthcoming regulatory control period and not thereafter. Nuttall Consulting considered that it would be reasonable to consider the end of the deferment benefits in the analysis, which SP AusNet does not consider in its analysis. Nuttall Consulting considered that this overstates the potential benefits of the program. Nuttall Consulting also considered that the proposed condition monitoring and power transformer refurbishment strategies would deliver less efficient outcomes than current practice because the benefits proposed by the programs are already being achieved by life extension.[633]

As stated in the draft decision, the AER notes that business process improvements which result in lower costs will be self financing as the net costs should be expected to be less than those reflected in the revenue requirement.[634] As discussed below, the AER considers that DNSPs are incentivised to self finance opex programs that deliver future period efficiency gains and do not require a step change allowance.

The AER considers that it is inappropriate to provide an opex allowance for increased expenditure that will lower a DNSPs future opex. If an opex allowance was provided this would alter the ratio to which the net benefits would be shared between the DNSP and network users. Under clause 6.5.8(a) of the NER, the AER is required to develop an EBSS that provides for a fair sharing between DNSPs and network users of efficiency gains and losses. The AER considers that if an opex allowance is provided

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631 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 264–265.

632 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 265.

633 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 264–265.

634 AER, *Draft decision*, Appendix L, p. 236.

to a DNSP that directly drives future efficiency gains then efficiency gains and losses will not be fairly shared between the DNSP and network users. The AER considers that it is inappropriate to provide an opex allowance for increased expenditure that will lower a DNSPs future opex. The AER considers that SP AusNet has sufficient opex in its base year expenditure, in addition to deferred capex, to undertake its condition monitoring program.

Having had regard to SP AusNet's initial and revised proposals and analysis done by and for the AER, the AER is not satisfied that the proposed expenditure for the condition monitoring program reasonably reflects the requirements of clauses 6.5.6(c)(1) of the NER.[635]Consequently the AER is not satisfied that the proposed step change reasonably reflects the efficient cost of a prudent DNSP.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of SP AusNet's revised regulatory proposals and other supporting information, the AER is not satisfied that the proposed expenditure for condition monitoring is consistent with a total forecast opex that reasonably reflects the efficient costs of a prudent DNSP to maintain its network.[636] In coming to this view the AER has had regard to the opex factors.[637]

L.5.16.4 Power transformer refurbishment

AER draft decision

The AER considered that the power transformer refurbishment program was not a step change because SP AusNet did not demonstrate that it was linked to a new or changed regulatory obligation or requirement and did not represent efficient costs required to achieve the opex objectives.[638]

The AER agreed with Nuttall Consulting, who stated that SP AusNet had not demonstrated the quantitative benefits associated with the project, nor had SP AusNet demonstrated that there was any driver that required anything other than an incremental change to its current practices. The AER also considered that business process improvements which result in lower costs will be self financing as the net costs should be less than those reflected in the revenue requirement.[639]

Victorian DNSP revised regulatory proposals

SP AusNet considered that the AER's rationale for rejecting this step change was flawed for the same reasons outlined in section L.5.16.3.[640]

SP AusNet argued that the benefits of this program exceeded the costs even under conservative assumptions. This analysis was combined with the condition monitoring program because both programs work in unison to deliver benefits.[641]

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635 Clauses 6.5.6(c)(1), 6.5.6(3), 6.5.6(a)(3), 6.5.6(a)(4) and 6.5.6(e)(1), 6.5.6(e)(3) of the NER.
636 Clauses 6.5.6(c)(1), 6.5.6(c)(3), 6.5.6(a)(3) and 6.5.6(a)(4).
637 Specifically opex factors (1), and (3).
638 AER, *Draft decision*. Appendix L, p. 234.
639 AER, *Draft decision*. Appendix L, p. 236.
640 SP AusNet, *Revised regulatory proposal*, p. 225.
641 SP AusNet, *Revised regulatory proposal*, p. 225.

Consultant review

Nuttall Consulting raised concerns with areas of the SP AusNet's NPV analysis of the power transformer refurbishment program. Specifically, Nuttall Consulting stated that:

- costs are not treated consistently between periods
- the present value treatment of costs is not consistent
- based on current age and replacement profiles, the proposed transformer refurbishment (and condition monitoring) strategies would deliver less efficient outcomes than current practice.[642]

Despite SP AusNet considering that its analysis was conservative, Nuttall Consulting considered that the issues with the analysis were significant enough to outweigh the potential conservatism. Nuttall Consulting considered that the analysis did not support the allowance of this proposed expenditure.[643]

Issues and AER considerations

The AER has had regard to SP AusNet's initial and revised regulatory proposals and has concerns with the NPV analysis performed by SP AusNet to justify the power transformer refurbishment program. The AER considers that the issues with SP AusNet's analysis as raised by Nuttall Consulting are significant enough to outweigh its potential conservatism. For example Nuttall Consulting noted that the costs for the power transformer refurbishment program only occur in the forthcoming regulatory control period and not thereafter. Nuttall Consulting considered that it would be reasonable to consider the end of the deferment benefits in the analysis, which SP AusNet does not consider in its analysis. Nuttall Consulting considered that this overstates the potential benefits of the program. Nuttall Consulting also considered that the proposed condition monitoring and power transformer refurbishment strategies would deliver less efficient outcomes than current practice because the benefits proposed by the programs are already being achieved by life extension.[644]

The AER notes that business process improvements which result in lower future costs will be self financing as the net costs should be expected to be less than those reflected in the revenue requirement.[645] The AER considers that it is inappropriate to provide an opex allowance for increased expenditure that will lower a DNSPs future opex. The AER considers that SP AusNet has sufficient opex in its base year expenditure, in addition to deferred capex, to undertake power transformer refurbishment. As discussed below, the AER considers that DNSPs are incentivised to self finance opex programs that deliver future period efficiency gains and do not require a step change allowance.

642 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, pp. 264–265.
643 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 265.
644 Nuttall Consulting, *Victoria electricity distribution price review: Revised proposals*, 22 October 2010, p. 264–265.
645 AER, *Draft decision*, Appendix L, p. 236.

The AER considers that it is inappropriate to provide an opex allowance for increased expenditure that will lower a DNSPs future opex. If an opex allowance was provided this would alter the ratio to which the net benefits would be shared between the DNSP and network users. Under clause 6.5.8(a) of the NER, the AER is required to develop an EBSS that provides for a fair sharing between DNSPs and network users of efficiency gains and losses. The AER considers that if an opex allowance is provided to a DNSP that directly drives future efficiency gains then efficiency gains and losses will not be fairly shared between the DNSP and network users.

Having had regard to SP AusNet's initial and revised proposals and analysis done by and for the AER, the AER is not satisfied that the proposed expenditure for the power transformer refurbishment program reasonably reflects the requirements of clauses 6.5.6(c)(1) of the NER.[646]Consequently the AER is not satisfied that the proposed step change reasonably reflects the efficient cost of a prudent DNSP.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of SP AusNet's revised regulatory proposals and other supporting information, the AER is not satisfied that the proposed expenditure for power transformer refurbishment is consistent with a total forecast opex that reasonably reflects the efficient costs of a prudent DNSP to maintain the quality, reliability and security of supply of standard control services and the reliability, safety and security of the distribution system through the supply of standard control services.[647] In coming to this view the AER has had regard to the opex factors.[648]

L.5.16.5 Substation earthing systems

AER draft decision

The AER considered SP AusNet's proposed step change regarding switchyard resurfacing and earth grid testing, totalling $1.0 million ($2010), to be part of the normal ongoing operations of a prudent and efficient DNSP. Accordingly, the AER did not accept SP AusNet's forecast step change for substation earthing systems on the basis that it should already be reflected in SP AusNet's base year expenditure.

Victorian DNSP revised regulatory proposals

SP AusNet disagreed with the AER's draft decision regarding substation earthing systems.[649] SP AusNet's revised regulatory proposal noted that the substation earthing systems step change consisted of two components:

1. the resurfacing being carried out in the switchyards of six substations
2. the earth grid current injection programme being enhanced in order to complete all zone substations by 2015.

In respect to the first point, SP AusNet reiterated that a substantial component of its switchyard resurfacing step change is non-recurrent.[650] Specifically, SP AusNet noted that:

646 Clauses 6.5.6(c)(1), 6.5.6(c)(3), 6.5.6(a)(3), 6.5.6(a)(4) and 6.5.6(e)(1), 6.5.6(e)(3) of the NER.
647 Clauses 6.5.6(c)(1), 6.5.6(c)(3), 6.5.6(a)(3) and 6.5.6(a)(4) of the NER.
648 Specifically opex factors (1), and (3).
649 SP AusNet, *Revised regulatory proposal*, p. 228.

> … the degradation [in the earthing system] does not miraculously coincide with the base year of a regulatory period—rather, it occurs over a long period of time—around 30 years…[651]

With regard to injection testing, SP AusNet stated that its proposed approach is consistent with a recent request from the ESV to regularly confirm the integrity of their installed earthing systems with respect to electrical safety.[652]

Consultant review

Nuttall Consulting agreed with SP AusNet that it is feasible for a period of 30 years to pass between remedial resurfacing works. However, Nuttall Consulting dismissed SP AusNet's assumption that all remediation work would occur in a designated short period. Specifically, Nuttall Consulting stated that:

> … the SP AusNet assumption that all remediation will occur in a designated short period is not supported by the age of the network and, specifically, the age of the substation switchyards themselves.[653]

Nuttall Consulting concluded, therefore, that the expenditure profile of switchyard resurfacing did not support a step change, but rather the ongoing process of remediation.[654]

Nuttall Consulting also noted the critical importance of inspection and testing of substation earths, and acknowledged that the ESV had requested confirmation of SP AusNet's testing program. Nuttall Consulting concluded, however, that the underlying requirements for a minimum of 10 yearly testing of substation earths had not changed. Nuttall Consulting added that testing of substation earths has been industry practice since at least the 1990's and most likely earlier. Accordingly, Nuttall Consulting stated that:

> [a]fter reviewing the information provided by SP AusNet in its revised proposal, Nuttall Consulting considers that the reinstatement of these step change costs is not substantiated.[655]

Issues and AER considerations

The AER notes that the Victorian DNSPs have had a legal obligation to comply with the Electricity Safety (Network Assets) Regulations since 1999, irrespective of the interpretation of those regulations by the ESV.[656] Moreover, the 2006–10 EDPR provided an allowance to SP AusNet for additional capex and/or opex to enable

650 SP AusNet, *Revised regulatory proposal*, p. 227.
651 SP AusNet, *Revised regulatory proposal*, p. 227.
652 SP AusNet, *Revised regulatory proposal*, p. 227.
653 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 266.
654 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 266.
655 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 266.
656 Specifically, regulation 27(2) of the Electrical Safety (Network Assets) Regulations required that earthing systems, except common multiple earthed neutral earthing systems, be inspected and tested at least every 10 years for compliance with regulation 23. The AER notes, however, that the Electrical Safety (Network Assets) Regulations sunset in December 2009. The obligations imposed by these regulations have been replaced with those in the DNSPs' ESMSs, as approved by ESV.

compliance with a number of these regulations, including those associated with regulation 27.[657]

Accordingly, the AER considers that switchyard resurfacing and earth grid testing are part of the normal ongoing operations of SP AusNet. Specifically, the AER considers that SP AusNet's base year opex, which captures the normal ongoing operating costs of SP AusNet, would already include the expenditure necessary to undertake switchyard resurfacing and earth grid testing.[658] The AER also notes that, with respect to switchyard resurfacing and earth grid testing, no relevant new regulatory obligations have been imposed on SP AusNet, nor have there been any relevant changes to the external operating environment over the 2001–05 and 2006–10 regulatory periods. Further, the significant underspend in opex over the previous and current regulatory periods highlights that SP AusNet has had the financial capacity to respond to these regulatory obligations as necessary.

The analysis provided by Nuttall Consulting also supports the AER's draft decision, that switchyard resurfacing and earth grid testing are a part of the normal ongoing operations of a prudent DNSP. In particular, Nuttall Consulting dismissed SP AusNet's assumption that all remediation work would occur in a designated short period:

> It is feasible that a period of 30 years could exist between remedial action in this area. However, the SP AusNet assumption that all remediation will occur in a designated short period is not supported by the age of the network and, specifically, the age of the substation switchyards themselves. The switchyards have been constructed over the last 80 years in the SP AusNet franchise. This long-term construction program means that degradation will have already occurred on many of the older sites and will continue to occur. This profile does not support a step change, but rather the ongoing process of remediation.[659]

The AER agrees with Nuttall Consulting, though also acknowledges that the maintenance works undertaken by SP AusNet will, to some degree, vary from year to year. That is, the tasks undertaken in a given year may not be the same as those undertaken in the base year. However, just because a given task was not undertaken in the base year does not imply that SP AusNet's base year opex is insufficient to undertake that task. For example, it is reasonable to expect other specific tasks which were undertaken in the base year may not need to be undertaken again for some period of time.

The AER, therefore, considers that any additional allowance for undertaking switchyard resurfacing and earth grid testing does not form part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs that SP AusNet would require to comply with all the applicable regulatory obligations or requirements associated with the provision of standard control services.[660]

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657 ESCV, *Electricity Distribution Price Review 2006–2010*, vol. 1, October 2006, p. 222.
658 AER, *Draft decision*, Appendix L, p. 176.
659 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 266.
660 Consistent with NER, cl. 6.5.6(c)(2) and 6.5.6(a)(2).

AER conclusion

For the reasons discussed above, the AER is not satisfied that the substation earthing systems step change proposed by SP AusNet forms part of a total forecast opex that reasonably reflects the opex criteria.

L.5.16.6 Substation site clean up

AER draft decision

In the draft decision, the AER rejected SP AusNet's proposal for $0.7 million ($2010) for asset retirement, site demolition and cleanup works resulting from redundancy of certain zone substations driven by proposed network augmentation projects.[661]

Victorian DNSP revised regulatory proposals

SP AusNet's revised proposal did not agree with the AER's draft decision to reject this step change, on the basis that:[662]

- the proposed additional expenditure is a by-product of SP AusNet undertaking its proposed capex program, and as a result, having to comply with existing obligations;
- inconsistency on the AER's part with the NER requirements – namely clauses 6.5.6(c)(1) and 6.5.6(c)(2) – and the requirements of section 7A(3) of the NEL;
- it is good industry practice for a DNSP to remediate all sites that it is not proposing to use, or where it will decommission assets;
- the remediation of sites was in "the long term interests of consumers of electricity" and moreover, the interests of the general public living in the vicinity of those sites, consistent with the National Electricity Objective.

Consultant review

The AER engaged Nuttall Consulting to assist the AER with its assessment of this step change. Nuttall Consulting considered that:

> With reference to the specific sites identified by SP AusNet, Nuttall Consulting considers that the proposed expenditures are reasonable and may reflect an additional level of expenditure above that of the current period. Nuttall Consulting recommends that the proposed step change expenditure is considered for inclusion in for allowances for the next period.[663]

Issues and AER considerations

Upon further consideration of the information including in and accompanying SP AusNet's building block proposal, the AER considers that this step change reflects a once-off cost that would be incurred by SP AusNet in the forthcoming regulatory control period due to a change in its operating environment, and would therefore not be included in SP AusNet's base year opex allowance. The AER considers the proposed expenditure forms part of a total forecast opex that reasonably reflects the opex criteria, in particular the costs a prudent DNSP in SP AusNet's circumstances

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661 AER, *Draft decision*, Appendix L, p. 233.
662 SP AusNet, *Revised regulatory proposal*, pp. 229–230.
663 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, p. 266.

would require to comply with its applicable regulatory obligations and requirements.[664]

AER conclusion

For the reasons discussed above, the AER considers that $0.7 million ($2010) for this step change as proposed by the SP AusNet is part of a total forecast opex that reasonably reflects the opex criteria.

Table L.58 AER conclusion on substation site cleanup expenditure ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Substation site cleanup	0.1	0.1	0.3	0.0	0.2	0.7

Source: AER analysis.

L.5.16.7 Substation civil infrastructure works

AER draft decision

The AER considered that the substation civil infrastructure works program was not a step change as SP AusNet did not demonstrate that it was linked to a new or changed regulatory obligation or requirement and did not represent efficient costs required to achieve the opex objectives.[665]

Victorian DNSP revised regulatory proposals

SP AusNet stated that the AER did not detail its reasons for rejecting this proposed step change in the draft decision. SP AusNet commented that it has been some time since such a program had been undertaken and it was therefore not included in its base year opex. SP AusNet stated that this is a 'lumpy' expenditure program that is efficient.[666]

Consultant review

Nuttall Consulting considered that the substation civil infrastructure works identified by SP AusNet were consistent with good industry practice. Nuttall Consulting pointed to several excerpts from SP AusNet's 2006 EDPR proposals that demonstrated that this type of expenditure is not new and has been previously identified by SP AusNet as a driver of expenditure in past periods. Nuttall Consulting therefore considered that identifying this expenditure as an opex step changes is not correct and that the proposed expenditure does not represent the efficient costs of achieving the operating expenditure objectives.[667]

Issues and AER considerations

The AER considers that Nuttall Consulting has sufficiently demonstrated that the substation civil infrastructure works identified by SP AusNet are consistent with good industry practice. For example Nuttall Consulting pointed to several excerpts from SP AusNet's 2006 EDPR proposals that demonstrated that this type of expenditure is

664 NER, clauses 6.5.6(c), 6.5.6(a)(2).
665 AER, *Draft decision*. Appendix L, p. 234.
666 SP AusNet, *Revised regulatory proposal*, pp. 229–230.
667 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 267–268.

not new and has been previously identified by SP AusNet as a driver of expenditure in past periods.[668]

The AER notes that the proposed expenditure is part of a 'lumpy' expenditure program and thus did not occur in the base year. However the AER notes that a prudent DNSP will undertake a number of 'lumpy' programs throughout the regulatory control period. SP AusNet has not identified the programs that did occur in the base year that will not be required in each year of the forthcoming regulatory control period. The AER considers that if an opex step change were given for each lumpy project or program that did not occur in the base year without removing lumpy programs from the base year then a DNSP would be provided with a greater forecast opex than it requires to maintain its network.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of SP AusNet's revised regulatory proposals and other supporting information, the AER is not satisfied that the proposed expenditure for substation civil infrastructure works is consistent with a total forecast opex that reasonably reflects the efficient costs of a prudent DNSP to maintain its network.[669] In coming to this view the AER has had regard to the opex factors.[670]

L.5.16.8 Substation fire systems

AER draft decision

The AER considered that the substation fire systems program was not a step change because SP AusNet did not demonstrate that it is linked to a new or changed regulatory obligation or requirement and did not represent efficient costs required to achieve the opex objectives.[671]

The AER noted that fire hydrants and hydrant systems in zone substations are subject to maintenance testing requirements. However, SP AusNet had not demonstrated that there had been any changes to these requirements, nor had it demonstrated how this program related to new or changed regulatory obligations. The AER considered that this program should already be a part of SP AusNet's ongoing opex.[672]

Victorian DNSP revised regulatory proposals

SP AusNet stated that the AER's definition of what constitutes a step change has no basis under the NER or the NEL and resubmitted its proposed allowance for this step change.[673]

Consultant review

Nuttall Consulting considered that the substation fire systems program proposed in SP AusNet's initial and revised regulatory proposals represent good industry practice and appeared consistent with SP AusNet's obligations. However SP AusNet had not

668 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 268.
669 Clauses 6.5.6(c)(2), 6.5.6(c)(3), 6.5.6(a)(3) and 6.5.6(a)(4) of the NER.
670 Specifically opex factors (1), (3) and (5).
671 AER, *Draft decision*. Appendix L, p. 234.
672 AER, *Draft decision*. Appendix L, pp. 234–235.
673 SP AusNet, *Revised regulatory proposal*, p. 231.

described how the activities that are driving the step change expenditure differ from current practice (the expenditure for which would already be provided for in the base year opex).[674]

Nuttall Consulting did not recommend the addition of this step change in the opex allowance for the forthcoming regulatory control period.[675]

Issues and AER considerations

The AER agrees with Nuttall Consulting that SP AusNet has not described any changes in regulatory obligations or changes in the operating environment that would justify this proposed step change. SP AusNet pointed to the requirements of Australian Standard AS 1851-2005. As stated in the draft decision, this standard is not newly established (it was published in September 2005) and SP AusNet has not demonstrated any changes to this standard. This expenditure would therefore be recovered through base opex.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of SP AusNet's revised regulatory proposals and other supporting information, the AER is not satisfied that the proposed expenditure for substation fire systems is consistent with a total forecast opex that reasonably reflects the efficient costs of a prudent DNSP to maintain its network.[676] In coming to this view the AER has had regard to the opex factors.[677]

L.5.16.9 Process and configuration management

AER draft decision

The AER considered that the process and configuration management program was not a step change because SP AusNet did not demonstrate that it is linked to a new or changed regulatory obligation or requirement and did not represent efficient costs required to achieve the opex objectives.[678]

Victorian DNSP revised regulatory proposals

SP AusNet stated that the AER did not detail its reasons for rejecting this proposed step change in the draft decision. SP AusNet reiterated the benefits of improving database management by moving to the Intelligence Electronic Device (IED61850) protocol among other initiatives and resubmitted its proposed allowance for this step change.[679]

Consultant review

Nuttall Consulting considered that SP AusNet already undertakes the activities driving the proposed process and configuration management opex step change, and

674 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 269.
675 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 269.
676 Clauses 6.5.6(c)(2), 6.5.6(c)(3), 6.5.6(a)(3) and 6.5.6(a)(4) of the NER.
677 Specifically opex factors (1), (3) and (5).
678 AER, *Draft decision*. Appendix L, p. 234.
679 SP AusNet, *Revised regulatory proposal*, pp. 231–233.

SP AusNet has not provided reasonable evidence that these costs are not currently undertaken and considered in the base year opex.[680]

If improvements to current practices are driving the proposed costs, Nuttall Consulting stated that the benefits identified by SP AusNet should relate to operating activities which in turn relate to opex efficiencies. However SP AusNet did not quantify these efficiencies, so it was not possible to consider whether the proposed expenditures are efficient.[681]

Nuttall Consulting did not recommend the addition of this step change in the opex allowance for the forthcoming regulatory control period.[682]

Issues and AER considerations

Having regard to the SP AusNet's initial and revised regulatory proposals, the AER concurs with Nuttall Consulting's assessment that it is not clear whether or not these costs are currently undertaken and considered in the base year opex. For example, SP AusNet states:

> Today, protection and control schemes are integrated within a single micro-processor based relay or Intelligence Electronic Device (IED)…
>
> The result of this is that all the configuration settings are electronically stored in data bases like TRESIS. TRESIS forms a data storage and a setting application management function. The process of developing and applying settings and the management of software versions and the configuration and the configuration of this growing array of micro-processors distributed in more than 60 sites right across eastern Victoria is a growing business need.[683]

It appears that these costs have already been incurred by SP AusNet in the past regulatory period. As such it would be considered in the base year opex with the expansion of this work being accounted for through the escalation factors.

The AER asked whether SP AusNet has performed a quantitative cost-benefit analysis of this program.[684] SP AusNet advised that a detailed quantitative assessment of the benefits is difficult and subjective because of the lack of independent data that formed part of SP AusNet's assessment, noting that this assessment reviews established protection and control practices of other Australian and world utilities.[685]

SP AusNet stated that the benefits of investing in network intelligence are predominantly based on ensuring normal functioning of the network and minimising the effects of abnormal adverse events in the face of underlying degradation of the network and to keep up with future technological advancements.[686] The AER

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680 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, pp. 269–270.

681 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 270.

682 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 270.

683 SP AusNet, *Revised regulatory proposal*, p. 232.

684 AER, Email request for information from SP AusNet, 24 September 2010.

685 SP AusNet, *Power cables and process and configuration*, 28 September 2010, p. 4.

686 SP AusNet, *Power cables and process and configuration*, 28 September 2010, pp. 3–4.

considers that these activities are a normal part of the operation of a prudent and efficient DNSP and supports the earlier consideration that the proposed costs for process configuration and management are incurred by SP AusNet in the course of past regulatory periods and would be included in the base opex.

Having had regard to SP AusNet's initial and revised proposals and analysis done by and for the AER, the AER is not satisfied that the proposed expenditure for the process and configuration management program reasonably reflects the requirements of clauses 6.5.6(c)(1) and (2) of the NER.[687] The AER does not consider that these costs are consistent with clause 6.5.6(c)(2) of the NER.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of SP AusNet's revised regulatory proposals and other supporting information, the AER is not satisfied that the proposed expenditure for process configuration management is consistent with a total forecast opex that reasonably reflects the efficient costs of a prudent DNSP to maintain its network.[688] In coming to this view the AER has had regard to the opex factors.[689]

L.5.16.10 PSAIDI reduction

AER draft decision

In its initial regulatory proposal SP AusNet proposed a step change of $19.9 million ($2010) to achieve in the 2011–15 regulatory control period a service reliability target of 34 minutes of planned SAIDI (PSAIDI) set by the ESCV in 2005.[690]

In the draft decision the AER noted that the PSAIDI target was an aspirational target that was set by the ESCV in the EDPR 2006–10.[691] Given the aspirational nature of this target, the AER considered that SP AusNet's proposal is not a step change as it is not based on a new or changed regulatory obligation or requirement. Notwithstanding this the AER recognised that there is merit in SP AusNet continuing to improve its PSAIDI.

The AER considered that it was not reasonable for SP AusNet's PSAIDI reduction expenditure to be included in its opex step changes and did not accept its proposed PSAIDI target step change of $19.9 million ($2010).[692]

In their initial regulatory proposals the other Victorian DNSPs did not propose a step change to achieve a PSAIDI target.

687 Clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(3), 6.5.6(a)(4) and 6.5.6(e)(1), 6.5.6(e)(3), 6.5.6(e)(5) of the NER.

688 Clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(3) and 6.5.6(a)(4) of the NER.

689 Specifically opex factors (1), (3) and (5).

690 SP AusNet, *Regulatory proposal*, p. 227 and Appendix I (Confidential), p. 5.

691 ESCV, *Electricity Distribution Price Review 2006–10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006. Final Decision Volume 1, Statement of Purpose and Reasons*, pp. 28–68.

692 AER, *Draft Decision*, Appendix L, p. 235.

Victorian DNSP revised regulatory proposals

In its revised regulatory proposal SP AusNet submitted that the draft decision did not reasonably consider the reasons and analysis SP AusNet provided to the AER in support of its PSAIDI target step change. SP AusNet noted that whilst the AER focused only on this being an 'aspirational target', SP AusNet proposed this step change as it considered there are net benefits to its customers from reducing PSAIDI.

SP AusNet did not accept the AER's draft decision and requested that the AER consider the information SP AusNet had provided in its initial proposal and in response to the follow up questions asked of it by the AER to determine whether there are net benefits to SP AusNet's customers, and make a decision based on this analysis. A failure to do so would, in SP AusNet's view, lead to an unreasonable outcome.[693]

In their revised regulatory proposals the other Victorian DNSPs did not propose a step change to achieve a PSAIDI target.

Issues and AER considerations

In response to SP AusNet's revised regulatory proposal the AER requested additional information from SP AusNet regarding the underlying costs, other calculations and timing assumptions associated with SP AusNet's PSAIDI target.[694]

As part of its response to the AER's request, SP AusNet revised its methodology for estimating the cost of achieving its PSAIDI target of 34 minutes and proposed a revised step change of $22.7 million ($2010) to achieve the target. The revised methodology incorporated the adoption of gross system capex, as opposed to total capex, as the driver for SP AusNet's PSAIDI performance,[695] the inclusion of up-to-date gross system capex forecasts and 2009 PSAIDI figures in the calculation, and revised costs based on up to date costs of portable generation. SP AusNet outlined that an increase in its annual gross system capex over 2011–15 relative to that in its 2009 base year would give rise to an increase in outages required for planned works (that is, declining PSAIDI performance). SP AusNet advised that through additional expenditure on and greater use of portable generation it could improve its PSAIDI performance. SP AusNet reiterated that its PSAIDI target of 34 minutes was based on the target previously supported by the ESCV and that the incremental benefit of achieving the target outweighed the incremental cost.[696]

The AER understands that the basis for the ESCV's PSAIDI target of 34 minutes for SP AusNet during the 2006–10 regulatory control period was SP AusNet's average PSAIDI performance during the 2001–04 period.[697] The ESCV noted in the EDPR

693 SP AusNet, *Revised regulatory proposal*, pp. 216–218.

694 SP AusNet, Response to information requested on 31 August 2010, 7 September 2010.

695 SP AusNet considered that increases in its capex would result in a deterioration in its PSAIDI performance. SP AusNet response to information request on 31 August 2010, 7 September 2010.

696 SP AusNet, Response to information requested on 31 August 2010, 7 September 2010.

697 ESCV, *Electricity Distribution Price Review 2006–10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006. Final Decision Volume 1, Statement of Purpose and Reasons*, p. 43.

2006–10[698] that the target it set reflected the reliability that customers should expect to experience over the 2006–10 regulatory period based on historical performance and the prices paid.[699] The ESCV's PSAIDI target was therefore aimed at maintaining the reliability of supply that customers had experienced over the 2001-04 period. The PSAIDI target was subject to monitoring and reporting by the ESCV but was not subject to financial incentives under the ESCV's s-factor scheme. SP AusNet did not receive a specific opex step change allowance to achieve the target in the 2006–10 regulatory period.

The AER notes that SP AusNet's PSAIDI performance has progressively improved each year over the current regulatory period, from 83.6 minutes in 2006, 77.4 minutes in 2007, 64.3 minutes in 2008, to 53.4 minutes in 2009.[700] SP AusNet has advised the AER that from 2007 it commenced a program to reduce its PSAIDI through an increased focus on work planning optimisation and application of isolated cases of portable generation.[701]

The AER has considered the information SP AusNet provided in its initial and revised regulatory proposals and in response to questions raised by the AER regarding its PSAIDI target step change. For the following reasons, the AER does not consider SP AusNet's proposed revised step change of $22.7 million ($2010) to achieve the PSAIDI target of 34 minutes is part of a total forecast opex that reasonably reflects the opex criteria:

- the relevant test in respect of step changes and opex generally is that the AER must be satisfied that it reasonably reflects the opex criteria and not solely whether there are net benefits for consumers

- the ESCV's PSAIDI target of 34 minutes is aspirational in nature and SP AusNet has not met this target during the current regulatory period and has not achieved PSAIDI of less than 36 minutes since 2002

- the AER does not have a power under the NER to specify or direct a DNSP to achieve a PSAIDI target and

- achieving the PSAIDI target of 34 minutes is not a regulatory obligation or requirement nor does it reflect any change in the relevant circumstances of SP AusNet.

There is, however, in the AER's view, merit in SP AusNet continuing to improve its PSAIDI performance and the AER will continue to monitor and report on this aspect

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698 ESCV, *Electricity Distribution Price Review 2006–10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006. Final Decision Volume 1, Statement of Purpose and Reasons*, p. 41.

699 It is noted that planned SAIDI was subject to financial incentives under the ESCV's s-factor scheme during the 2001–05 regulatory period but was removed from the scheme in the EDPR 2006–10. ESCV, *Electricity Distribution Price Review 2006–10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006. Final Decision Volume 1, Statement of Purpose and Reasons*, p. 81.

700 Email from SP AusNet providing data for the AER's Victorian electricity distribution comparative performance report, 15 February 2010.

701 SP AusNet, Response to information requested on 31 August 2010, 7 September 2010.

of the service reliability of the Victorian DNSPs during the 2006–10 regulatory period.

In response to SP AusNet's submission that increasing capex over the forthcoming regulatory control period necessarily reduces PSAIDI and therefore justifies this step change, the AER does not agree. Specifically, the AER has observed that SP AusNet's average PSAIDI performance during the 2006–09 period is 69 minutes although its performance has progressively improved each year over this period, as outlined above. This improvement has been achieved notwithstanding that SP AusNet's net system capex has increased over the 2006–09 period. Specifically, SP AusNet's net system capex increased by 33 per cent and 26 per cent in 2008 and 2009 (relative to the previous years) respectively while its PSAIDI performance in 2008 and 2009 improved by 16 per cent in both years. SP AusNet's net system capex increased by 3 per cent in 2007 (relative to the previous year) while its PSAIDI performance in 2007 improved by 7 per cent.

At 53.4 minutes, SP AusNet's PSAIDI performance in its opex base year of 2009 is a notable improvement on its average performance over the previous years of the current regulatory period. SP AusNet's total net system capex (actual and 2010 forecast) will have increased by 54 per cent in the 2006–10 regulatory period compared to the 2001–05 regulatory period. As outlined above, SP AusNet's PSAIDI performance has progressively improved each year over the current regulatory period notwithstanding its increase in capex during this period. The AER considers that given the level of increase (25.4 per cent) in SP AusNet's approved net system capex allowed for in this final decision in the 2011–15 regulatory control period compared to the 2006–10 regulatory period, it is reasonable to conclude that SP AusNet's base year opex is part of a total forecast opex that reasonably reflects the opex criteria and is sufficient for SP AusNet to maintain its quality and reliability of supply as measured by PSAIDI and to meet or manage the expected demand for standard control services.[702] The AER understands that the purpose of the PSAIDI target set by the ESCV was to maintain the quality and reliability of supply achieved over the 2001-04 period. Under the NER, this very purpose is reflected is one of the operating expenditure objectives in clause 6.5.6(a) of the NER. The total forecast opex the AER is satisfied reasonably reflects the opex criteria, as set out in chapter 7, in part addresses that objective. This is another reason why the AER does not consider SP AusNet's proposed step change of $22.7 million is justified.

AER conclusion

For the reasons discussed above, the AER does not consider SP AusNet's proposed revised step change of $22.7 million ($2010) to achieve the PSAIDI target of 34 minutes is part of a total forecast opex that reasonably reflects the opex criteria. The AER therefore considers that a total forecast opex that reasonably reflects the opex criteria would not include such an allowance.[703]

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702 NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(1), 6.5.6(a)(3), 6.5.6(a)(4).

703 NER, clauses 6.5.6(e)(1), 6.5.6(e)(5).

L.5.16.11 Leasing of fleet and major facilities

AER draft decision

In its initial regulatory proposal SP AusNet proposed $4.49 million ($2010) in increased costs for leasing its fleet (trucks and vehicles) and $3.23 million ($2010) in increased costs for leasing its works depot facilities [commercial in confidence].[704]

Due to an oversight the AER did not review these proposed increases in costs in its draft decision.

Victorian DNSP revised regulatory proposals

In its revised regulatory proposal SP AusNet commented that the AER's draft decision provided no substantive discussion as to why these opex forecasts were rejected and that the AER had failed to advise SP AusNet of the relevant material issues considered by the AER in its decision on this issue. SP AusNet noted that it did not accept the AER's draft decision and has resubmitted the cost forecasts for leasing of fleet and major facilities in its revised regulatory proposal.[705]

In regard to leasing of facilities, SP AusNet explained that all of its major facilities will continue to be leased, with no change to the number of assets being leased, however, there are changes in the expected real costs of leasing two facilities—Lilydale and South Morang— which have been included in the opex forecasts. SP AusNet noted that these cost increases reflect known circumstances that will affect these facilities in the 2011–15 regulatory control period.

In regard to leasing of fleet, SP AusNet explained that its fleet opex costs are expected to increase over the forthcoming regulatory period, due to an increase in costs for vehicles that are currently leased and because existing fleet that is currently owned by SP AusNet will reach the end of its economic life and be replaced with new, leased fleet. SP AusNet commented that this change has been modelled based on the expected useful lives of all existing fleet items, along with the lease costs on a like-for-like replacement of that fleet. SP AusNet noted that it has included in its PTRM the asset disposals associated with the sale of fleet it currently owns during the forthcoming regulatory control period.

SP AusNet stated that its analysis shows that it is economic to continue its leasing arrangements for its facilities and fleet and that consequently no capex associated with these two items has been included in its regulatory proposals.[706]

Issues and AER considerations

In response to SP AusNet's revised regulatory proposal the AER requested additional information regarding SP AusNet's leasing costs for fleet and facilities. SP AusNet responded to the AER's request and provided the additional information that the AER requested.

[704] SP AusNet, *Regulatory proposal,* pp. 214-215.
[705] SP AusNet, *Revised regulatory proposal,* pp. 191–193.
[706] SP AusNet, *Revised regulatory proposal,* pp. 191–193.

[commercial in confidence].[707]

[commercial in confidence].

[commercial in confidence].[708]

[commercial in confidence][709]

[commercial in confidence].[710]

[commercial in confidence].[711]

[commercial in confidence] [712]

707 SP AusNet, Response to information requested on 1 September 2010, 3 September 2010; SP AusNet, Response to information requested on 8 September 2010, 10 September 2010.

708 SP AusNet, Response to information requested on 1 September 2010, 3 September 2010; SP AusNet Response to information requested on 8 September 2010, 10 September 2010.

709 SP AusNet, Response to information requested on 8 September 2010, 10 September 2010.

710 SP AusNet, Response to information requested on 24 September 2010, 27 September 2010.

711 SP AusNet, Response to information requested on 24 September 2010, 27 September 2010.

712 NER, clauses 6.5.6(a)(3) & 6.5.6(a)(4).

[commercial in confidence,].[713]

[commercial in confidence].[714]

Regarding the leasing of fleet, SP AusNet has advised the AER that a key driver of the forecast cost increase for leasing of vehicles and trucks is future truck lease costs relative to current lease costs. SP AusNet explained that in the current regulatory period its truck lease costs reflected the low residual value of its current truck fleet, for which the lease was transferred to SP AusNet from TXU after Singapore Power purchased TXU in 2006. The residual value underpinning the lease costs at the time of the transfer was discounted to reflect that the fleet being transferred was not new. As this truck fleet is replaced in the future, the new lease cost incurred by SP AusNet will reflect the value of a new fleet item which is significantly more than the lease cost for older fleet. SP AusNet noted that this primarily affects trucks during the 2011–15 regulatory control period due to the longer life of trucks.[715]

The AER considers that for SP AusNet to achieve several of the operating expenditure objectives under the NER,[716] an opex step change allowance for the leasing of fleet in the 2011–15 regulatory control period is required. The AER has accepted the information provided by SP AusNet discussed above to justify the increase in its fleet lease costs and is satisfied that SP AusNet's forecast step change of $4.49 million ($2010) form part of a total forecast opex that reasonably reflects the opex criteria. [717] In coming to this view the AER has considered the operating expenditure factors in the NER. [718]

713 CB Richard Ellis, *MarketView Melbourne Industrial 2Q 2010*, 2010. Accessed at http://www.cbre.com.au/EN/Research/Industrial.htm.
714 NER, clauses 6.5.6(e)(1) & 6.5.6(e)(5).
715 SP AusNet, Response to information requested on 8 September 2010, 10 September 2010.
716 NER, clauses 6.5.6(a)(3) & 6.5.6(a)(4).
717 NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(3), 6.5.6(a)(4).
718 NER, clauses 6.5.6(e)(1), 6.5.6(e)(5), 6.5.6(e)(7).

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of the SP AusNet's regulatory proposals and other supporting information, the AER is satisfied that SP AusNet's proposed step change for the incremental leasing costs of its fleet (trucks and vehicles) forms part of a total forecast opex that reasonably reflects the opex criteria but is not satisfied that increased lease costs for facilities at [confidential] forms part of a total forecast opex that reasonably reflects the opex criteria.[719] In coming to this view the AER has had regard to the opex factors.[720]

The AER is satisfied that its estimate of step changes of:

- $1.3 million (2010) for SP AusNet's proposed step change for the incremental leasing costs of its works depot facilities at [confidential]and
- $4.49 million (2010) for the incremental leasing costs of its fleet (trucks and vehicles)

forms part of a total forecast opex that reasonably reflects the opex criteria.[721] The AER's conclusions here are set out in table L.59 below.

Table L.59 AER conclusion on SP AusNet leasing costs for fleet and facilities performance expenditure ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Leasing of fleet	–0.39	0.52	0.81	1.55	2	4.49
Leasing of facilities—[confidential]	0.00	0.00	0.22	0.53	0.53	1.30

Source: AER analysis

L.5.16.12 Incremental vegetation growth

AER draft decision

The AER considered that SP AusNet's proposal to remove more vegetation outside of the mandated clearance space was not a step changes because SP AusNet had not demonstrated it was linked to a new or changed regulatory obligation. The AER noted that SP AusNet's initial regulatory proposal explicitly stated that the proposal was being driven by its desire to 'enhance' outcomes. Consequently, the AER considered that SP AusNet had not demonstrated that this proposal represented the efficient costs required to achieve the opex objectives in clause 6.5.6(a) of the NER.[722]

Victorian DNSP revised regulatory proposals

SP AusNet stated that its modelling showed that its proposed approach to vegetation management has the lowest NPV of costs in the long term, and therefore, represented

[719] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(3), 6.5.6(a)(4).
[720] NER, clauses 6.5.6(e)(1), 6.5.6(e)(5), 6.5.6(e)(7).
[721] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(3), 6.5.6(a)(4).
[722] AER, *Draft decision*, Appendix L, p. 234.

‘the efficient costs of achieving the operating expenditure objectives’.[723] The costs for the proposed step change are outlined in table L.60.

Table L.60 Revised proposed incremental vegetation growth step change ($’000 2010)

2011	2012	2013	2014	2015	Total
2612	3135	1358	731	627	8464

Source: SP AusNet, Response to information requested 11 August 2010, 18 August 2010.

Issues and AER considerations

The AER notes that during the late 1990s SP AusNet pursued a vegetation management approach similar to its proposed incremental growth step change. SP AusNet removed a higher proportion of immature trees which reduced the number of trees that encroached on the clearance space in the medium to longer term, reducing its cyclic cutting costs.[724]

However, from the early 2000s, SP AusNet focused on maintaining adherence to the regulated clearance space, rather than removing immature trees that would eventually grow into the clearance space, reducing its vegetation management costs.[725] Under the incentive based regulatory framework SP AusNet retained those cost savings.

Since 2007, SP AusNet’s vegetation management costs have risen, in part due to an increase in trees encroaching on the clearance space as a result of this earlier management decision.[726]

In its revised regulatory proposal SP AusNet’s stated that:

> … if proposed opex expenditure delivers opex efficiency benefits in future regulatory control periods, then future opex forecasts will, by definition, factor this into their Proposals, as the AER must assess the prudency and efficiency of operating expenditure each regulatory re-set period. As such, opex incurred in one regulatory period that reduces the longer term opex costs of a business will not be self financing, again, because business’ can’t internalise that efficiency benefit.[727]

Further:

> … businesses are not incentivised to self finance expenditure, as they are unable to capture the efficiency benefits associated with that expenditure; this is contrary to the achievement of the NEO.[728]

The AER considers these statements to be inconsistent with its approach to forecasting operating expenditure and its application of the efficiency benefit sharing scheme.

723 SP AusNet, *Revised regulatory proposal*, p. 217.
724 SP AusNet, *Regulatory proposal*, Appendix I, confidential, p. 47.
725 SP AusNet, *Regulatory proposal*, Appendix I, confidential, p. 47.
726 SP AusNet, *Regulatory proposal*, Appendix I, confidential, p. 47.
727 SP AusNet, *Revised regulatory proposal*, p. 207.
728 SP AusNet, *Revised regulatory proposal*, p. 207.

To forecast opex, the AER takes the actual opex incurred in the base year (typically the penultimate year of the prior regulatory control period) and adds (subtracts) scale and real cost increases (decreases) and adds step changes. The AER does not adjust opex forecasts for forecast efficiency improvements. This incentivises DNSPs to identify and implement efficiency improvements. The operation of the EBSS then serves to share the gains from efficiency improvements between the DNSP and network users.

Consequently the AER considers that DNSPs are incentivised to self finance opex programs that deliver future period efficiency gains because those efficiency gains will not be recovered until after they occur and the EBSS ensures that DNSPs are able to retain those efficiency savings for five years after the cost saving is made. This is the case regardless of whether the efficiency savings occur within the same regulatory control period as the opex is incurred or a later regulatory control period.

The AER considers that it is inappropriate to provide an opex allowance for increased expenditure that will lower a DNSPs future opex. If an opex allowance was provided this would alter the ratio to which the net benefits would be shared between the DNSP and network users. Under clause 6.5.8(a) of the NER, the AER is required to develop an EBSS that provides for a fair sharing between DNSPs and network users of efficiency gains and losses. The AER considers that if an opex allowance is provided to a DNSP that directly drives future efficiency gains then efficiency gains and losses will not be fairly shared between the DNSP and network users.

AER conclusion

For the reasons discussed above the AER is not satisfied that SP AusNet's proposed incremental growth expenditure is consistent with a total forecast opex that reasonably reflects the opex criteria, and in particular the efficient costs that a prudent DNSP would require to meet the opex objectives.

The AER considers that SP AusNet has sufficient opex in its base year expenditure, in addition to retained efficiency savings in previous and future years, to undertake its line clearance program. The AER has also provided SP AusNet a step change for the increased vegetation management costs required to meet new regulatory obligations under the Electricity Safety (Electric Line Clearance) Regulations 2010 as discussed in section L.5.1.2. SP AusNet's proposed incremental vegetation growth step change is not required to meet those new obligations. The AER does not consider it appropriate to provide an opex allowance to fund efficiency savings as the EBSS ensures that SP AusNet will retain those efficiency savings for a period of five years thereby sharing those savings fairly between SP AusNet and its network users.

L.5.16.13 Conductor tie replacement

AER draft decision

SP AusNet did not include an opex step change for the replacement of conductor ties in its initial regulatory proposal. Consequently the AER did not consider this replacement program in the draft decision.

Victorian DNSP revised regulatory proposals

SP AusNet included in its revised regulatory proposal a new opex step change of $3.2 million ($2010) for increasing the number of conductor ties it replaces over the forthcoming regulatory control period to reduce the risk of bush fires.[729]

SP AusNet stated that this new step change was required on the basis of new information from two separate audits:

1. an independent contractor engaged by SP AusNet to audit its steel conductors, fittings and tie conditions
2. an annual bushfire mitigation audit, conducted by ESV and its technical consultant, IJM Consulting.[730]

The first audit, completed in January 2010, concluded that there was no immediate need to replace a large volume of steel conductor ties, but that it may be prudent to progressively increase conductor tie replacements for those conductors that are not planned to be replaced during the forthcoming regulatory control period.[731]

The second audit, conducted by ESV, made four recommendations concerning steel conductor tie condition and replacement, including that SP AusNet develop ‘a detailed strategy to replace corroding steel ties and conductors now widespread across the business.’[732]

Having had regard to these audits, SP AusNet considered that a combination of conductor replacement (capex) and conductor tie replacement (opex) would address the network risks identified. SP AusNet also considered that this step change was required to meet the general duty under the Electricity Safety Act to minimise hazards and risks as far as practicable.[733]

Issues and AER considerations

The AER notes that a DNSP may only make revisions to its regulatory proposal ‘to address matters raised by the draft distribution determination or the AER’s reasons for it’.[734]

Despite this, the AER notes that audits by both SP AusNet and ESV have identified conductor ties as being a significant safety risk and that SP AusNet is required under the Electricity Safety Act to minimise hazards and risks as far as practicable.

ESV reviewed SP AusNet’s conductor tie replacement program and stated that it supported the need for the program and considered that the number of conductor ties proposed to be replaced appeared reasonable.[735] Having considered the advice of ESV and the audits undertaken, the AER is satisfied that a prudent DNSP should replace

729 SP AusNet, Response to information requested on 11 August 2010, 18 August 2010.
730 SP AusNet, *Revised regulatory proposal*, p. 250.
731 SP AusNet, *Revised regulatory proposal*, p. 250.
732 SP AusNet, *Revised regulatory proposal*, p. 250.
733 SP AusNet, *Revised regulatory proposal*, p. 250. Section 98 of the *Electricity Safety Act 1998*.
734 Clause 6.10.3(b) of the NER.
735 ESV, *Assessment by Energy Safe Victorian of EDPR safety-related programs*, 18 October 2010, p. 22.

the number of conductor ties proposed by SP AusNet during the forthcoming regulatory control period.

The AER notes that SP AusNet determined a unit rate of $300 per span based on replacing the ties on seven poles per day with a three man crew, using an elevated platform vehicle, construction truck, and allowing resources for supervision and 10 per cent traffic control. The AER considers these assumptions to be reasonable. However it notes that SP AusNet did not identify the labour rates assumed or the cost of the vehicles.

SP AusNet's estimated cost of replacing cable ties of $300 per span equates to a crew costing approximately $441 000 per FTE (assuming 210 work days per year and a crew replacing the ties on 7 poles per day) not taking into account the costs of traffic management. On the basis that each crew includes three men plus a supervisor and two vehicles this rate appears reasonable. Consequently the AER is satisfied that a cost of $300 per span to replace cable ties reasonably reflects the efficient cost of replacement.

AER conclusion

For the reasons discussed above, the AER considers $3.2 million ($2010) for this step change as proposed by SP AusNet is part of a total forecast opex that reasonably reflects the opex criteria, and in particular the efficient expenditure required by a prudent operator to comply with the Electricity Safety Act.

L.5.16.14 Enhanced asset inspection programs

AER draft decision

SP AusNet did not include an opex step change for enhanced asset inspection programs in its initial regulatory proposal. Consequently the AER did not consider these inspection programs in the draft decision.

Victorian DNSP revised regulatory proposals

In 2009, SP AusNet trialled the use of helicopter mounted, high resolution digital photography with GPS tracking to inspect overhead line assets. This trial inspected 15 500 poles and detected 1092 asset maintenance and replacement items. The program cost $580 000 in the 2009 calendar year.[736]

SP AusNet's bushfire mitigation management committee subsequently endorsed this inspection program as an effective means of asset condition inspection and monitoring.[737] The incremental cost of the proposed inspection program is outlined in table L.61.

[736] SP AusNet, *Revised regulatory proposal*, p. 252.
[737] SP AusNet, *Revised regulatory proposal*, p. 252.

Table L.61 SP AusNet proposed step change for enhanced asset inspection programs ($'000s 2010)

2011	2012	2013	2014	2015	Total
1171	1171	1171	1171	1171	5857

Source: SP AusNet, Response to information requested on 11 August 2010, 18 August 2010.

SP AusNet stated that the proposed enhanced asset inspection program was a lower cost option than age based replacement and was required to meet the general duty under the Electricity Safety Act to minimise hazards and risks as far as practicable.[738]

Consultant review

Nuttall Consulting reviewed SP AusNet's proposed enhanced asset inspection program and considered that there were a large number of benefits of the program that accrue to SP AusNet that were not accounted for in the analysis.[739]

Issues and AER considerations

The AER notes that a DNSP may only make revisions to its regulatory proposal 'to address matters raised by the draft distribution determination or the AER's reasons for it'.[740]

Despite this the AER notes that the failure of assets in hazardous bushfire risk areas (HBRA) can have significant consequences and that SP AusNet is required under the Electricity Safety Act to minimise hazards and risks as far as practicable.

ESV reviewed SP AusNet's proposed enhanced asset inspection program and stated that it supported the need for the program and considered that the proposed number of spans to be inspected appeared reasonable.[741]

Consequently the AER is satisfied that it is reasonable for SP AusNet to undertake the proposed enhanced asset inspection program in order for it to comply with its obligations under the Electricity Safety Act, given the advice provided to it by ESV.

However, Nuttall Consulting noted that some of the defective assets detected would otherwise have been detected by SP AusNet's current ground based inspection program prior to the asset failing.[742] Thus the AER considers that SP AusNet's analysis of the proposed enhanced asset inspection program overstates its benefits.

Nuttall Consulting also noted that SP AusNet state that its proposed enhanced asset inspection program will deliver 'substantial net benefits' but does not explicitly identify what those benefits will be.[743]

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738 SP AusNet, *Revised regulatory proposal*, p. 253; Section 98 of the *Electricity Safety Act 1998*.
739 Nuttall Consulting, p. 38.
740 Clause 6.10.3(b) of the NER.
741 ESV, *Assessment by Energy Safe Victorian of EDPR safety-related programs*, 18 October 2010, p. 22.
742 Nuttall Consulting, p. 38.
743 SP AusNet, *Revised regulatory proposal*, p. 252.

Nuttall Consulting considered that the likely benefits will include reduced operating and maintenance expenditure relating to reduced asset failures and more timely replacement of assets. Nuttall Consulting note that SP AusNet did not quantify these benefits.[744]

The AER notes that to the extent that the proposed enhanced inspection program reduces the number of assets failing while in service, this would reduce the frequency of unplanned outages occurring in SP AusNet's network. Under the STPIS SP AusNet would be rewarded for this performance improvement.

Thus the AER considers that some of the benefits of the proposed inspection program will accrue to SP AusNet in addition to the network safety benefits that will accrue to the wider community.

The AER considers that any step change provided to SP AusNet to undertake the proposed enhanced inspection program should be net of the benefits that accrue to SP AusNet since it should be able to fund the proposed program from those benefits. However, the AER notes that benefits that will accrue will be both internal to SP AusNet and external to the wider community.

Further, in regard to the costs of the proposed enhanced asset inspection program the AER notes that SP AusNet has assumed the same unit costs for inspection during the forthcoming regulatory control period as was expended during the 2009 trial of the program. That is, SP AusNet has not assumed any economies of scale or improved efficiency from improved work practices and greater learning by doing in a full roll out. The AER considers that in moving from a trial to a fully implemented program SP AusNet should be able to undertake the proposed asset inspection at a lower unit rate.

Consequently, the AER is not satisfied that the enhanced asset inspection program step change proposed by SP AusNet reasonably reflects the efficient costs required by a prudent DNSP to comply with the Electricity Safety Act.

The AER notes that in its assessment of economies of scale that will accrue to SP AusNet due to network growth, it considered that there will be efficiencies of scale of 55.6 per cent for the escalation of base opex (see appendix J). The AER considers it reasonable to assume that similar scale efficiencies will be realised in expanding SP AusNet's current enhanced asset inspection trial. Applying these economies of scale to SP AusNet's enhanced asset inspection step change reduces it to $520 000 ($2010) each year. The AER considers this reduction to be a conservative estimate of the internal benefits given that SP AusNet would accrue other efficiencies in a fully implemented program, as discussed above.

AER conclusion

For the reasons discussed above, the AER considers its estimate outlined in table L.62 is part of a total forecast opex that reasonably reflects the opex criteria, and in

744 Nuttall Consulting, , p. 38.

particular the efficient expenditure required by a prudent operator to comply with the Electricity Safety Act.[745]

Table L.62 AER conclusion on SP AusNet's enhanced asset inspection program step change ($'000s 2010, excluding escalation, overheads and margins)

2011	2012	2013	2014	2015	Total
520	520	520	520	520	2600

Source: AER analysis.

L.5.17 Additional step changes proposed by United Energy

The AER did not accept in the draft decision five additional step changes proposed by United Energy in its initial regulatory proposal. United Energy did not agree with the AER's draft decision and included step changes in its revised regulatory proposal for:

- crime stopper license fees
- earth testing in non CMEN areas
- extreme event management
- premium feed in tariff
- static guard / patrol.

L.5.17.1 Crime Stoppers licence fees

AER draft decision

[commercial in confidence].

However, the AER noted that any business process improvements which result in lower costs should be self financing, as the net costs would be expected to be less than those reflected in JEN's and United Energy's opex allowances.[746]

Accordingly, the AER was not satisfied that the proposed step change, amounting to $0.04 million ($2010) for JEN and $0.1 million ($2010) for United Energy, reasonably reflected the opex criteria, including the opex objectives.[747]

Victorian DNSP revised regulatory proposals

JEN's revised regulatory proposal agreed with the AER's draft decision [commercial in confidence, commercial in confidence, commercial in confidence].[748]

745 NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), and 6.5.6(a)(1).
746 AER, *Draft decision*, Appendix L, p. 208.
747 AER, *Draft decision*, Appendix L, p. 209.
748 JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, pp. 6–8.

Conversely, United Energy disagreed with the AER's draft decision, and proposed that the full amount of $0.08 million ($2010) was required over the forthcoming regulatory control period.[749]

United Energy added that the proposed step change was not included in the scope of outsourced work that was tendered, nor was it included in United Energy's in-house expenditure forecasts.[750] Further, the activity is expected to increase security at United Energy's premises, and reduce theft.[751]

Issues and AER considerations

The AER considers that United Energy's revised regulatory proposal does not provide any further justification from that in its initial regulatory proposal as to why this step change is necessary. That said, the AER has reconsidered the case put forward by United Energy in its revised regulatory proposal.

Specifically, United Energy's revised regulatory proposal stated that incurring the Crime Stoppers licence fee is 'expected to increase security at UED premises, and reduce theft'.[752] The AER acknowledged this in its draft decision:

> The AER notes that the implementation of the Copper Theft Strategy appears to have been successful in reducing the costs associated with copper theft.[753]

Further, the AER's draft decision noted that the benefits to United Energy of implementing such a strategy appear to greatly outweigh the costs.

> … the AER considers that any business process improvements which result in lower costs should be self financing …[754]

That is, the AER considers the net costs to United Energy of the Crime Stoppers licence fees would be expected to be less than those reflected in United Energy's opex allowance. The AER considers, therefore, that any additional allowance for Crime Stoppers licence fees cannot form part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs of maintaining the quality, reliability and security of supply of standard control services or maintaining the reliability, safety and security of the distribution system through the supply of standard control services. [755]

The AER also acknowledges that United Energy has undertaken a bottom-up build of costs, and that the costs of the Crime Stoppers licence fees have not been included in the tendered costs to service United Energy's network.

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749 The AER notes that this amount reflects the total expenditure proposed by United Energy in its original regulatory proposal. However, subsequent to this proposal, United Energy provided the AER with an amended (and significantly lower) amount.
750 United Energy, *Revised regulatory proposal*, p. 93.
751 United Energy, *Revised regulatory proposal*, p. 93.
752 United Energy, *Revised regulatory proposal*, p. 93.
753 AER, *Draft decision*, Appendix L, p. 208.
754 AER, *Draft decision*, Appendix L, p. 208.
755 Consistent with the NER, cl. 6.5.6(c)(1), 6.5.6(a)(3) and 6.5.6(a)(4).

The AER, however, has assessed United Energy's regulatory proposal in accordance with a revealed costs approach. As such, a base year opex amount has been derived from a combination of Jemena Asset Management's 2008 regulatory accounts and United Energy's internal cost models.[756] The AER considers that these base year costs capture the normal ongoing operating costs of United Energy, which would include the Crime Stoppers licence fees. The AER, therefore, considers that any additional allowance for Crime Stoppers licence fees cannot form part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs that United Energy would require to maintain the quality, reliability and security of supply of standard control services, and the reliability, safety and security of the distribution system.[757]

AER conclusion

For the reasons discussed above, the AER is not satisfied that the Crime Stoppers licence fee step change proposed by United Energy forms part of a total forecast opex that reasonably reflects the opex criteria.

L.5.17.2 Earth testing in non CMEN areas

AER draft decision

The AER noted that the Victorian DNSPs have had a legal obligation to comply with regulations governing earth testing of non-CMEN areas since 1999. Further, the AER noted that the 2006–10 EDPR provided an allowance to enable compliance with these regulations.[758]

The AER's draft decision also considered that the significant opex underspend over the 2001–05 and 2006–10 regulatory control periods demonstrated that both JEN and United Energy had the financial capacity to respond to these obligations.[759]

As such, the AER was not satisfied that JEN's and United Energy's proposed additional expenditure to undertake earth testing of non-CMEN areas, of $0.6 million ($2010) and $2.5 million ($2010) respectively, reasonably reflected the opex criteria.

Victorian DNSP revised regulatory proposals

JEN's revised regulatory proposal agreed with the AER's draft decision to not accept additional funding for earth testing of non-CMEN areas.[760]

Conversely, United Energy disagreed with the AER's draft decision, and proposed that the full amount of $2.5 million ($2010) was required over the forthcoming regulatory control period.[761]

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756 Refer to appendix I for further discussions regarding the AER's approach to assessing United Energy's proposed opex forecasts.

757 Consistent with the NER, cl. 6.5.6(c)(1), 6.5.6(a)(3) and 6.5.6(a)(4).

758 ESCV, *Electricity Distribution Price Review 2006–2010*, vol. 1, October 2006, p. 222.

759 AER, *Draft decision*, Appendix L, p. 209.

760 JEN, *Revised regulatory proposal*, Appendix 7.2, pp. 6–8.

761 The AER notes that this amount reflects the total opex proposed by United Energy in its original regulatory proposal. However, subsequent to their initial regulatory proposal, United Energy

United Energy stated that the proposed step change was not included in the scope of outsourced work that was tendered, nor was it included in United Energy's in-house expenditure forecasts.[762] Further, United Energy contended that it plans to undertake the work, and accordingly, should be provided with the opex to enable it to implement these plans.[763]

Issues and AER considerations

The AER considers that United Energy's revised regulatory proposal does not provide any further justification from that in its initial regulatory proposal as to why this step change is necessary. That said, the AER has reconsidered the case put forward by United Energy in its revised regulatory proposal.

Specifically, the AER notes that the Victorian DNSPs have had a legal obligation to comply with the Electricity Safety (Network Assets) Regulations since 1999.[764] Moreover, the 2006–10 EDPR provided an allowance to United Energy for additional capex and/or opex to enable compliance with a number of these regulations, including those associated with regulation 27.[765]

Accordingly, the AER considers that earth testing in non-CMEN areas are part of the normal ongoing operations of United Energy. Specifically, the AER considers that United Energy's base year opex, which captures the normal ongoing operating costs of United Energy, would include sufficient expenditure to cover the costs associated with earth testing in non-CMEN areas.[766] Further, the significant underspend in opex over the previous and current regulatory control periods demonstrates that United Energy has had the financial capacity to respond to these regulatory obligations as necessary.

The AER, therefore, considers that any additional allowance for earth testing in non-CMEN areas cannot form part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs that United Energy would require to comply with all the applicable regulatory obligations or requirements associated with the provision of standard control services.[767]

provided the AER with an amended (and significantly lower) amount. United Energy, Response to information requested 22 January 2010, 8 February 2010.

762 United Energy, *Revised regulatory proposal*, p. 92.

763 United Energy, *Revised regulatory proposal*, p. 92.

764 Specifically, regulation 27(2) of the Electrical Safety (Network Assets) Regulations required that earthing systems, except common multiple earthed neutral earthing systems, be inspected and tested at least every 10 years for compliance with regulation 23. The AER notes, however, that the Electrical Safety (Network Assets) Regulations sunset in December 2009. The obligations imposed by these regulations have been replaced with those in the DNSPs' ESMSs, as approved by ESV.

765 ESCV, *Electricity Distribution Price Review 2006–2010*, vol. 1, October 2006, p. 222.

766 The AER acknowledges that United Energy has undertaken a bottom-up build of costs, and that the costs of earth testing non-CMEN areas have not been included in the tendered costs to service United Energy's network. The AER, however, has assessed United Energy's regulatory proposal in accordance with a revealed costs approach. As such, a base year opex amount has been derived from a combination of Jemena Asset Management's 2008 regulatory accounts and United Energy's internal cost models. For further discussions regarding the AER's approach to assessing United Energy's proposed opex forecasts, refer to appendix I.

767 Consistent with the NER, cl. 6.5.6(c)(1) and 6.5.6(a)(2).

AER conclusion

For the reasons discussed above, the AER is not satisfied that United Energy's proposed step change for earth testing in non-CMEN areas forms part of a total forecast opex that reasonably reflects the opex criteria.

L.5.17.3 Premium feed in tariff

AER draft decision

In the draft decision, the AER did not accept United Energy's proposed step change, totalling $0.9 million ($2010), to recover the administrative costs of managing and complying with the premium feed-in tariff (PFIT) scheme. The AER discussed this issue in chapter 4 of its draft decision, which set out the AER's draft decision on the control mechanism for standard control services. Specifically, the AER noted that:

> The AER considers that United Energy's proposal to include the administrative costs of managing and complying with the PFIT scheme in forecast opex … is not permissible under the NER. The AER is only able to accept forecast opex under clause 6.5.6(c) of the NER if it is satisfied that the total of the opex reasonably reflects the opex criteria. These criteria always refer back to the opex objectives. It is unclear how the administrative costs of the PFIT scheme relate to the opex objectives listed in clause 6.5.6(a) of the NER… Consequently, it appears that administrative costs cannot be considered as distribution services under the NER.[768]

Victorian DNSP revised regulatory proposals

United Energy's revised regulatory proposal stated that it has a legal obligation to pay the PFIT rebate and a legal obligation to administer the system. United Energy noted that these obligations arise under relevant Victorian law.[769]

In addition to their revised regulatory proposal, United Energy submitted updated forecasts to the AER on 15 October, 2010.[770] These forecasts increased United Energy's proposed step change for the recovery of the administrative costs of managing and complying with the PFIT scheme from $0.9 million ($2010), as submitted in United Energy's revised regulatory proposal, to $4.5 million ($2010) over the 2011–15 regulatory control period.

Issues and AER considerations

The AER did not accept United Energy's proposed step change to recover the administrative costs of managing and complying with the PFIT scheme because the AER did not consider the administrative costs constituted a distribution service under the NER. The AER notes that this issue has since been clarified by the Australian Energy Market Commission (AEMC). Specifically, the AEMC has stated that:

> [t]he Commission considers that the costs to administer and comply with these [feed-in] schemes would fall under costs required to comply with regulatory obligations or requirements associated with the provision of standard control services, in the same way as administrative costs for complying with other regulatory obligations faced by DNSPs. For this reason, the Commission considers that the costs for administering the

768 AER, *Draft decision*, p. 63.
769 United Energy, *Revised regulatory proposal*, p. 93.
770 United Energy, Email to the AER, 15 October.

> schemes would be within the requirements for operating expenditure under the Rules and not require any additional clarification under the Rules.[771]

Given the clarification provided by the AEMC, the AER accepts, in principal, United Energy's proposed step change to recover the administrative costs of managing and complying with the PFIT scheme. The AER, however, is not satisfied that the proposed costs are consistent with a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs of managing and complying with the PFIT scheme.

Specifically, the AER notes that United Energy has forecast a constant level of expenditure for each year of the forthcoming regulatory control period. The AER considers that such a forecast is not consistent with the projected installation of photovoltaic (PV) systems for Victoria, as forecast by ACIL Tasman. ACIL Tasman, in their report prepared for the AER's final decision, considered that the take-up of PV systems would peak in 2009–10, before reducing to significantly lower levels for the remainder of the 2011–15 regulatory control period. This profile is shown in table L.63.

Table L.63 ACIL Tasman proposed take-up of solar panels in Victoria

	2008–09	2009–10	2010–11	2011–12	2013–14	2014–15	2015–16
Number of panels installed	10000	14000	5000	5000	5000	4000	3000

Source: ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, Final report, April 2010, p. 34.

The AER has adjusted the ACIL Tasman profile of the take-up of solar panels to reflect calendar year estimates. These estimates, as shown in table L.64, have assumed a simple average of consecutive years. For example, the 2010 calendar year estimate represents half of ACIL Tasman's forecast for 2009–10, and half of the forecast for 2010–11.

Table L.64 AER's conclusion on the proposed take-up of solar panels in Victoria

	2010	2011	2012	2013	2014	2015
Number of panels installed	9500	5000	5000	4500	3500	3000

Source: AER analysis.

The AER considers that it is reasonable to expect that, over the 2011–15 regulatory control period, the administrative costs of managing and complying with the PFIT scheme will be strongly correlated with the take-up of solar panels in Victoria.[772] Specifically, United Energy has referred to a range of additional tasks associated with managing solar panel connections.[773] The AER considers that given the nature of these tasks the level of resources required to manage and comply with the PFIT

[771] Australian Energy Market Commission, *Rule determination, National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010*, July 2010, p. 15.

[772] The AER also considers that the number of solar panels installed by United Energy, as a percentage of the solar panels installed throughout Victoria, is likely to remain relatively constant throughout the forthcoming regulatory control period.

[773] United Energy, Email to the AER, 15 October.

scheme would be strongly correlated with solar panel take-up. As such, the AER has adjusted United Energy's proposed step change on a pro-rata basis to match the profile forecast by ACIL Tasman. That is, the AER considers that United Energy's forecasts for 2010 are consistent with the installation of 9500 solar panels, and that the subsequent costs forecast should reflect the reduced number of PV installations expected, consistent with table L.64.

Consequently, the AER has adjusted United Energy's opex forecast downwards by $2.5 million ($2010) over the forthcoming regulatory control period. The AER considers that this adjustment reflects the minimum change necessary to provide opex forecasts for the recovery of the administrative costs that are consistent with a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs that a prudent operator in the circumstances of United Energy would require to manage and comply with the PFIT scheme.[774]

AER conclusion

For the reasons discussed above, the AER considers its estimate of $2.0 million ($2010) for this step change is consistent with a total forecast opex that reasonably reflects the opex criteria.

L.5.17.4 Static guard patrol

AER draft decision

In the draft decision, the AER did not accept this step change on the basis that United Energy did not demonstrate to the AER's satisfaction that there was any significant change in its operating environment due to an increase in either theft or vandalism to warrant a step change.[775]

Victorian DNSP revised regulatory proposals

In its revised regulatory proposal, United Energy stated that its static guard patrol step change was proposed because it was not included in the scope of outsourced work that was tendered, or United Energy's in-house expenditure forecast. United Energy also stated that other DNSPs received operating expenditure allowances for such activities, but did not provide any evidence of this.[776] United Energy resubmitted its proposal for $0.1 million ($2010).

Issues and AER considerations

Based on the information included in and accompanying United Energy's regulatory proposals, the AER is not satisfied that this expenditure proposal can form part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs of achieving the opex objectives as required by clause 6.5.6(c)(1) of the NER.

In response to an information request, United Energy explicitly stated that there is no specific new or changed obligation that has triggered this step change. Instead,

[774] Consistent with the NER, cl, 6.5.6(c)(1), 6.5.6(c)(2), 6.5.6(a)(1) and 6.5.6(a)(2).
[775] AER, *Draft decision*, Appendix L, p. 210.
[776] United Energy, *Revised regulatory proposal*, p. 93.

United Energy considered that an increase in the level of theft and public activism warrants more than the ad hoc patrol that United Energy currently employs.[777]

However, United Energy has not sufficiently demonstrated that there has been an increase in theft or activism to a level requiring a patrol at certain premises on a fortnightly or monthly basis, or that the current ad hoc patrol is insufficient.[778] Specifically, the AER considers that United Energy's base year opex, which captures the normal ongoing operating costs of United Energy, would include sufficient expenditure to cover the costs associated with zone substation security.[779] Further, the significant underspend in opex over the previous and current regulatory control periods demonstrates that United Energy has had the financial capacity to respond to security and activism threats.[780] The AER is therefore not satisfied that incremental expenditure above the current base year amount for the ad hoc patrol can form part of a total forecast opex for United Energy that reasonably reflects the opex criteria, in particular the efficient costs of maintaining the reliability, safety and security of its network.[781]

In response to United Energy's statement that the other Victorian DNSPs have been provided with an expenditure allowance for this step change, the AER notes it did not accept the same step change for [commercial in confidence, commercial in confidence, commercial in confidence].[782]

AER conclusion

For the reasons discussed above, the AER considers the step change for static guard patrol proposed by United Energy is not part of a total forecast opex that reasonably reflects the opex criteria.

L.5.18 Additional step changes proposed by Powercor

L.5.18.1 Powercor at risk townships

AER draft decision

The AER concluded that the Victorian Government's township protection plans announcement did not impose any obligations on DNSPs to undertake fire mitigation strategies for towns covered by the plan.[783] In reply to AER inquiries, Powercor

777 United Energy, Response to information requested on 22 January 2010, 22 February 2010.

778 ibid.

779 The AER acknowledges that United Energy has undertaken a bottom-up build of costs, and that the costs of providing static guard/patrol security have not been included in the tendered costs to service United Energy's network. The AER, however, has assessed United Energy's regulatory proposal in accordance with a revealed costs approach. As such, a base year opex amount has been derived from a combination of Jemena Asset Management's 2008 regulatory accounts and United Energy's internal cost models. For further discussions regarding the AER's approach to assessing United Energy's proposed opex forecasts, refer to appendix I.

780 NER, cl. 6.5.6(e)(5).

781 NER, cll. 6.5.6(c)(1), 6.5.6(a)(4).

782 JEN, *Revised regulatory proposal*, Appendix 7.2, p. 10.

783 Premier of Victoria, www.premier.vic.gov.au/newsroom/7841.html accessed 7 January 2010. See also *Statement of Government Intentions,* February 2010, pp. 2, 18; AER, *Draft decision*, Appendix L, pp. 231–232.

observed that there was no regulatory obligation imposed by the township protection plan.[784]

Furthermore, the AER concluded that Powercor's at risk townships proposal pre-empted the Victorian Bushfires Royal Commission (VBRC) recommendations and the Victorian Government's response.[785]

The AER's draft decision did not accept Powercor's proposed $22 million ($2010) expenditure associated with the at risk township plan because it did not reasonably reflect the opex criteria, including the opex objectives.[786]

Victorian DNSP revised regulatory proposals

Powercor concurred with the AER's draft decision that no regulatory obligation existed to undertake the at risk townships program.

However, Powercor stated that its program should be supported because:

- Powercor seeks to minimise fire risk within its network boundary and its plan complements the Victorian government's bushfire initiative
- a prudent operator could not ignore exposing itself to the risks of legal challenge and community backlash by ignoring the heighted fire danger in the towns earmarked by the Government
- clause 3.1 of the *Electricity Distribution Code* (EDC) requires DNSPs to operate their network according to 'good electricity industry practice' and Powercor has a duty to develop maintenance practices that meet the needs of its customers and the network without reliance on government regulation or legislation
- the AER's consultant, Nuttall Consulting, considered the benefits of the at risk township program were material
- the AER's statement that Powercor could self finance the at risk townships plan was incorrect and inconsistent with the operation of the EBSS, which does not consider public benefits
- additional cost–benefit analysis undertaken revealed the program was NPV positive over 20 years for eight of ten scenarios considered
- a legislative response implementing the Victorian Bushfires Royal Commission recommendations could take years, whereas DNSPs could reduce fire risk from their assets immediately
- whether SP AusNet proposed a similar plan or not was not relevant to the opex criteria

[784] Powercor, meeting with AER staff and Nuttall Consulting, 24 February 2010.
[785] AER, *Draft decision*, Appendix L, p. 232.
[786] AER, *Draft decision*, Appendix L, p. 232.

- there was no certainty that Powercor could seek a pass through from the AER for the costs associated with implementation of VBRC recommendations
- Nuttall Consulting's report did not provide conclusive evidence that Powercor's forecast costs were high and that rejecting expenditure associated with line surveys, LIDAR and independent audits was not supported by evidence.[787]

Powercor further noted it had already commenced the program and had revised expenditure down to $19.4 million ($2010) from $22 million ($2010).[788]

Consultant review

The AER engaged Nuttall Consulting to review its recommendations regarding the at risk townships costs proposed by Powercor.

Nuttall Consulting considered that Powercor has not accurately reflected its view that the at risk townships program had material benefits. Nuttall Consulting observed that its comment was in the context of Powercor generating benefits in the form of likely operating efficiencies, which Powercor had nevertheless not identified.[789]

In support of this view, Nuttall Consulting concluded that the costs proposed by Powercor for the 38 townships overlap with other protection areas in 24 of the 38 townships and that Powercor had not identified any reduction in costs associated with the overlap. Nuttall Consulting also observed that Powercor's proposed expenditure on research activities did not include any forecast of associated benefits. Noting the lack of a regulatory obligation requiring Powercor to undertake the at risk townships project, Nuttall Consulting recommended that Powercor's revised regulatory proposal step change opex of $19 million ($2010) not be accepted.

Issues and AER considerations

The AER and Powercor agree that no regulatory obligation exists in respect of at risk townships. However, the AER accepts that a step change may not only be brought about by a change in regulatory obligations but also by a change in circumstances not reflected in the base year opex, which the AER considers forms part of a total forecast opex that reasonably reflects the opex criteria. In this case, the AER is of the view that the February 2009 bushfires represents a change in circumstances. For this reason the AER has further considered this proposed step change.

Powercor has stated that a common driver of expenditure is risk mitigation or avoided cost; in this case, reduced fire risk as it relates to risk mitigation. The AER has assessed whether risk mitigation is appropriate for inclusion as a step change. In assessing risk, the AER also considered the costs, benefits and impacts of implementing Powercor's at risk townships program in relation to the regulatory regime, including the NER and the VBRC final recommendations. In undertaking this assessment, the AER has taken into account opex factors (3), (4) and (5), which it considers are of particular relevance.

787 Powercor, *Revised regulatory proposal*, pp. 188–191.
788 Powercor, *Revised regulatory proposal*, p. 192.
789 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 358.

The VBRC's recommendations were published on 31 July 2010 and include a wide range of measures. Recommendation 30 provides that the Victorian Government should amend the regulatory framework to require DNSPs to introduce measures that reduce the fire risk posed by hazard trees. Recommendation 31 provides that municipal councils should be responsible for identifying hazard trees and notifying responsible entities of their location.

At the time of this final decision, recommendation 31 has been enacted, However, recommendation 30 has not yet been enacted. It is not clear when recommendation 30 will be enacted by the Victorian Government and if this occurs, what instrument will be used.

As discussed in the introduction to the opex chapter, the AER must accept the total of a DNSP's proposed forecast opex if it is satisfied that it reasonably reflects the opex criteria. Step changes form one component of the total forecast opex. The AER has therefore assessed whether the proposed opex for step changes is consistent with a total forecast opex that reasonably reflects the opex criteria.[790]

The opex criteria in turn refer to achieving the opex objectives. The opex objectives require a DNSP to include in its building block proposal the total forecast opex for the regulatory control period that the DNSP considers is required to, among other things:

> (3) maintain the quality, reliability and security of supply of standard control services; and
>
> (4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In the AER's view 'maintain' refers to expenditure required to retain the status quo or to continue current arrangements in place. The AER does not consider that this captures expenditure to introduce new arrangements.

The AER notes that a significant part of Powercor's territory was affected by the February 2009 bushfires. It is reasonable for Powercor to consider the risk of fire starts in its area and take account of new information before it, such as the Victorian Government's press releases on township protection plans (i.e. 'at risk townships' as described by Powercor).[791]

The AER notes that the Victorian Government's press releases on township protection plans do not impose any obligation explicitly or otherwise on the Victorian DNSPs. This is not disputed by Powercor.[792] The press release refers only to fire protection agencies and their involvement in managing the risk poses by bushfires in the affected towns:

> The CFA is leading the development of the Town Protection Plans and will deliver a standardised statewide format for the plans. It is working with local

[790] Specifically opex factors (1), (3), (4) and (5).

[791] Premier of Victoria, *Premier calls Victorian communities to action*, 18 August 2009.

[792] Powercor, *Revised regulatory proposal*, p. 188.

> councils and engaging local communities to explore local knowledge, history, culture and people's needs in the development of the plans.[793]

The AER considers that government or community expectations for improved service standards are not captured by the opex objectives where such expectations are not reflected in or imposed by regulatory obligations or requirements. As noted in the draft decision the AER does not consider it appropriate to pre-empt the Victorian Government's response to the VBRC's final recommendations. In addition, the AER notes that there is no overriding public benefits test in the NER. The AER considers that public benefits identified by Powercor are not relevant to its assessment of opex expenditure, notwithstanding that Nuttall Consulting agreed with Powercor's statement that:

> … anticipated benefits of the program are to reduce as far as practicable the risk of fires caused by asset failure or vegetation impacting on power lines.[794]

In regard to Powercor's contention that its proposed expenditure is also required to meet the requirements of good asset management in clause 3.1 of the EDC, the AER has taken this into account when assessing the proposed expenditure against the opex objectives and the opex factors.

The AER has had regard to Nuttall Consulting's advice that the costs proposed by Powercor for the 38 townships overlap with other protection areas in 24 of the 38 townships and that Powercor has not identified any reduction in costs associated with the overlap.[795]

Nevertheless, in assessing risk, the AER has given due consideration to SP AusNet's proposed activities for high resolution aerial photography as part of its enhanced asset management program, which it submitted to ESV for evaluation against its regulatory obligations. SP AusNet's service area is comparable to Powercor's service area in respect of potential bushfire risk.

ESV has advised the AER that it considered SP AusNet's proposal reasonable.[796] On this basis, the AER has provided SP AusNet's proposed costs (approximately $3.8 million ($2010)) as a step change for the forthcoming regulatory control period. The AER considers this proposal is consistent with the requirement to comply with regulatory obligations or requirements in clause 6.5.6(a)(2) of the NER, as a result of ESV's endorsement on safety grounds.

The AER observes that, unlike its electric line clearance step change proposal, Powercor did not lodge its 'at risk township' protection plan with ESV for review.

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793 Premier of Victoria, *Premier calls Victorian communities to action*, 18 August 2009.

794 Nuttall Consulting, *Report–Capital expenditure, Victorian electricity distribution revenue review, final report*, 4 June 2010, p. 345.

795 Nuttall Consulting. *Victorian electricity distribution revenue review: Revised proposals*, 22 October 2010, p. 359.

796 ESV, *Assessment by Energy Safe Victoria of EDPR Safety-Related Programs*, 18 October 2010, p. 24.

Nevertheless, the AER considers that Powercor's proposed LIDAR aerial imaging is similar to that proposed by SP AusNet for high resolution aerial photography and considered by ESV.

As the AER has provided step change funding for SP AusNet's proposal, the AER considers it reasonable that Powercor should also be provided with opex to undertake the same activities. The AER has therefore accepted Powercor's proposed $4.1 million ($2010) for LIDAR aerial imaging. This expenditure is provided in accordance with clause 6.5.6(a)(2) of the NER.

Powercor also proposed $2.25 million ($2010) for research into new technologies.[797] In considering this proposal, the AER notes Nuttall Consulting's advice that no evidence was provided by Powercor as to the likely benefits (in terms of reduced operating expenditure resulting from fewer outages associated with vegetation contact with network assets and reduced outages from asset failure) of this research that would accrue to it.[798] The AER considers that this is a key deficiency in Powercor's proposal and therefore does not consider this proposal can form part of a total forecast opex that reasonably reflects the opex criteria.

In respect of Powercor's proposed $1.4 million ($2010) for ground fuel reduction as noted in the AECOM report, the AER notes that Powercor accepted the AER's draft decision to reject proposed costs associated with the findings in the AECOM report.

The AER also considered:

- the *Electricity Safety Act 1998*, as amended by the *Energy and Resources Legislation Amendment Act 2010*, and notes that the Act will require municipal councils (not DNSPs) to identify and notify distributors of trees that are likely to fall onto, or come into contact with, an electric line.
- that the ESV has not indicated that other DNSPs should undertake additional ground fuel reduction activities in their network areas.
- on this basis, and further noting the nature of the 2010 Line Clearance Regulations (see below), Powercor has no obligation to undertake any further assessment of hazard trees.
- that Powercor is proposing to include costs that the AER considers will be borne by municipal councils.

Therefore, the AER has not accepted Powercor's revised regulatory proposal to seek funding for ground fuel reduction activities as part of its at risk townships proposal on the basis that it does not consider this proposal can form part of a total forecast opex that reasonably reflects the opex criteria..

797 Includes activities for powerline carrier noise detection, pulse intellirupters, ground fault neutraliser, SWIER early monitoring system, investigation into replacing certain fuses with fault tamers and transformers with sealed components.

798 Nuttall Consulting, *Victorian electricity distribution revenue review: Revised proposals* , 22 October 2010, pp. 361–362.

For these reasons, the AER has reduced Powercor's proposed step change expenditure for hazard trees identification by $5 million over 2011–15 .

The AER has also amended Powercor's high powered ground photography costs from the proposed $3.5 million ($2010), by deducting $1 million ($2010) for the costs already provided in Powercor's base opex from 2009, to arrive at a step change of $2.5 million ($2010).

The AER notes that if the Victorian Government imposes an obligation on Powercor to undertake the activities proposed in its at risk townships proposal, as noted in chapter 16, a DNSP can apply to the AER to pass through costs which meet the definition of a regulatory change event or a service standard event. In assessing such a pass through application the AER would have regard to the opex step changes approved in this final decision, among other things.

Taking into account the VBRC's final recommendations, Nuttall Consulting's advice and the AER's view of the Electric Line Clearance 2010 Regulations, the AER has not accepted Powercor's proposed opex step change expenditure for at risk townships in its totality having had regard to clauses 6.5.6(c)(1)(2) and (3) and 6.5.6(a)(2)(3) and (4) of the NER. The AER has amended Powercor's proposed at risk townships opex step change to $9.5 million ($2010) which it considers provides Powercor with forecast opex that reasonably reflects clause 6.5.6(c)(1)(2) and (3) of the NER.

AER conclusion

For the reasons discussed above and as a result of the AER's consideration of Powercor's revised regulatory proposal and other supporting information, the AER does not consider that Powercor's proposed opex step change for at risk township protection plans forms part of a total forecast opex that reasonably reflects the opex criteria.

Based on its analysis of Powercor's revised regulatory proposal, the VBRC's final recommendations, advice from Nuttall Consulting and the AER's view of the Electric Line Clearance 2010 Regulations, the AER has amended Powercor's at risk townships proposed expenditure to $9.5 million ($2010) which it considers forms part of a total forecast opex that reasonably reflects the opex criteria, in particular the efficient costs of a prudent operator to achieve the opex objectives given a realistic expectation of cost inputs. In coming to this view the AER has had regard to the opex factors. Table L.65 sets out the AER's conclusion on Powercor's at risk townships plan.

Table L.65 AER conclusion on Powercor's at risk township protection plans ($'000, 2010)

2011	2012	2013	2014	2015	Total
1 909	1 909	1 909	1 909	1 909	9 545

Source: AER analysis.

L.6 AER conclusion

This appendix has assessed the proposed allowance for operating expenditure step changes which is one component of each Victorian DNSP's proposed total forecast operating expenditure. The AER considers that the level of expenditure determined in this appendix is consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast operating expenditure reasonably reflects the operating expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast operating expenditure.

That constituent decision, which should be read together with this appendix, is discussed at chapter 7.

Table L.66 sets out the AER's conclusion on the amounts that will be added to the base operating and maintenance expenditure for each distributor for costs associated with opex step changes. These tables also include opex allowances associated with overhead cost allocation which are discussed in chapter 7.

Table L.66 AER conclusion on step changes to opex for 2011–15 ($'000, 2010)

Step changes	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
DNSP specific	7 252.0	9 544.7	6 741.2	7 601.3	1 995.0	33 134.2
AMI related	–	–	810.1	–	2 269.2	3 079.3
Climate change	–	–	–	–	–	–
Customer communications	1 818.0	4 143.1	5 040.5	5 116.3	3 135.0	19 252.9
Demand management	–	–	–	8 248.0	3 000.0	11 248.0
Electricity safety regulations	10 860.6	60 297.4	11 363.8	88 129.4	35 673.2	206 324.4
Environmental obligations	–	–	151.9	–	200.0	351.9
Capex/opex balance	–	–	787.2	–	95.0	882.2
Information technology	–	–	3 853.5	37 358.2	–	41 211.7
Insurance	692.0	2 722.0	–	26 886.7	3 530.0	33 830.7
National framework for distribution network planning and expansion	2 720.0	4 276.0	1 490.3	1 900.0	1 390.0	11 776.3
Other issues	300.0	300.0	300.0	–	300.0	1 200.0
Regulatory submission costs	1 717.2	4 006.8	4 421.0	2 970.2	2 227.7	15 342.9
Total	**25 359.7**	**85 290.0**	**34 959.4**	**178 210.1**	**53 815.1**	**377 634.3**

Note: Totals may not add due to rounding.

The step changes for each DNSP for each year of the forthcoming regulatory control period are outlined in table L.67.

Table L.67 AER conclusion on step changes by year, all Victorian DNSPs, 2011–15 ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	6.5	5.6	5.6	3.8	3.9	25.4
Powercor	21.8	20.8	14.7	14.0	13.9	85.3
JEN	8.1	6.1	5.3	8.7	6.8	35.0
SP AusNet	29.8	33.6	35.6	39.7	39.4	178.2
United Energy	11.1	11.4	9.7	11.0	10.7	53.8
Total	**77.3**	**77.5**	**70.9**	**77.3**	**74.6**	**377.6**

Note: Totals may not add due to rounding.

M Self insurance

This appendix sets out the AER's considerations in assessing the Victorian DNSPs' proposed self insurance amounts in their revised regulatory proposals.

For clarity, the AER notes that self insurance is a component of operating expenditure (opex). Self insurance allowances provide compensation for risks (and subsequent costs) faced by the DNSP, which are not already recovered through

- the DNSP's base year expenditure (the AER's analysis and decision on appropriate base year amounts can be found at chapter 7 of this final decision)
- the DNSP's cost input and scale escalators (the AER's analysis and decision on scale and cost escalators can be found at appendices J and K of this final decision) or
- the DNSP's approved opex step changes (the AER's analysis and decision on opex step changes can be found at chapter 7 and appendix L of this final decision.

As noted at the beginning of the opex chapter (chapter 7), each Victorian DNSP proposed an allowance for self insurance, as a component of their total proposed forecast operating expenditure for the 2011-15 regulatory control period. The assessment of that self insurance is relevant to determining whether the AER is satisfied as to whether the total proposed forecast operating expenditure or its estimate of the required operating expenditure reasonably reflects the operating expenditure criteria.

Specifically, this appendix assesses the proposed allowances and the level of efficient expenditure for self insurance which a prudent operator, in the actual circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the operating expenditure objectives.[1]

As is discussed further in this appendix, the AER considers that the operating expenditure factors 1, 2, 3 and 5 are particularly relevant to this assessment.

M.1 AER draft decision

The AER's draft decision set out several considerations in the assessment of the Victorian DNSPs' self insurance proposals.[2] In that decision, the AER broadly considered self insurance allowances for:

- insurance deductibles for externally held insurance policies
- risks not compensated for the opex base year calculations
- A summary of the AER's positions in its draft decision on individual risks proposed by the Victorian DNSPs are set out below.

1 As per the AER's obligations under clause 6.5.6 of the NER.
2 AER, *Victorian Distribution determination 2011-2015, Draft decision*, appendix M, pp. 245-252.

Liability risks (including bushfire liability)

All five DNSPs proposed self insurance allowances for liability risks.[3]

The AER, in its draft decision rejected the liability risks proposed by CitiPower, Powercor and SP AusNet.[4] For CitiPower and Powercor, the AER considered that a representative amount for these risks was already provided in each business' base year.

SP AusNet and Powercor, in addition to loss history, included adjustments to each of their self insurance allowances, based on the projected impacts of climate change (which were quantified in the study *'Bushfire Weather in Southeast Australia')*.[5]

The AER, in its draft decision rejected the arguments put forward for these adjustments in relation to fire liability. The AER also rejected adjustments made for additional fire liability losses:

> The AER notes that a 'major' fire event (that is, an event that may be described as a 'one in twenty year' event) has already occurred on SP AusNet's network, in February 2009. The policy deductible for bushfire claims is $10 million. Aon asserts that for a one in twenty year event, SP AusNet would incur that total cost of the deductible (that is, the liability would be beyond $10 million). However, the AER notes that the liability quantified so far (as at July) for 2009 is only at $1 963 637.[6] The full cost of liabilities arising from the February 2009 bushfire event are yet to be quantified. The AER considers that the full costs should be representative of a major fire event and a forward looking self insurance allowance can be based on those losses. As a result, once costs have been quantified (the AER expects that this will happen as part of SP AusNet's revised regulatory proposal, and as the actual costs for 2009 will form the base year for the purposes of forecasting opex over 2011–15), the AER can make an assessment of the actual cost impacts of such an event, and determine an appropriate self insurance allowance for the deductible (if any) to compensate for any future events.
>
> The AER intends to undertake a similar assessment of increased fire risks for Powercor, once 2009 actual costs are available, as Powercor also experienced major bushfires on its network in 2009.

In its draft decision, the AER stated that it would revisit the actual liability costs for 2009 arising from bushfire events for Powercor and SP AusNet and use these costs to determine an appropriate self insurance allowance (if any) to compensate for one in twenty year bushfire events.[7]

For asbestos liability, United Energy claimed a separate allowance of $24 000 per annum. The AER, in its draft decision, accepted this allowance as it related to a deductible amount on an externally held insurance policy. JEN also proposed self

3 CitiPower, *Regulatory proposal*, pp. 179–184; Powercor, *Regulatory proposal*, pp. 178–184; JEN, *Regulatory proposal*, pp. 138–140; SP AusNet, *Regulatory proposal*, p. 231; United Energy, *Regulatory proposal*, p. 80.

4 AER, *Draft decision*, appendix M, pp. 253 - 255.

5 *Bushfire weather in Southeast Australia*, commissioned by the Climate Institute, conducted by Bushfire Co-operative Research Centre, the Bureau of Meteorology, and CSIRO Marine and Atmospheric Research.

6 Aon, *SP AusNet self insurance report*, appendix 1, attachment 1.

7 AER, *Draft decision*, appendix M, p. 253.

insurance allowances for deductibles for third party property damage, public fatality and public injuries, which the AER also accepted.[8]

Property risks (including third party damage to DNSP assets)

All five Victorian DNSPs proposed self insurance allowances for various property risks.

The AER in the draft decision rejected JEN's proposed self insurance allowance for zone station catastrophic or component failure and pole fires.[9] This was on the basis that incurred costs from these events would likely be capex, and rolled into (and recovered through) the RAB. The AER noted that the only residual costs to JEN are the financing costs between the time the expenditure is incurred and the end of the regulatory control period when these costs are rolled into the RAB. The AER also considered these costs to be insignificant, and that they would be outweighed by upside risks inherent in the regulatory regime. The AER rejected JEN's proposed allowance for other assets (lighting and storms) on the basis that a reflective amount for these risks was already provided for in the base year.[10]

Accordingly, the AER stated that, if JEN provided substantiated frequency of 'other' lightning events data for 2009, it would consider whether a self insurance allowance should be provided at the time of the final distribution determination.[11]

CitiPower, Powercor and United Energy each proposed an allowance for general property risks. The AER in the draft decision rejected CitiPower and Powercor's proposed amounts for general property risks as it considered that these risks were already compensated for in the base year. [12]

For United Energy, the AER noted that the main property loss under this category was a $1.78 million transformer fire in 2004. The AER considered that this would have been a capital cost. The AER, therefore, rejected the self insurance allowance for 2011-2015 on the basis that, should the event occur in the forthcoming regulatory control period, those undepreciated costs would also be rolled into the RAB for the following reset.[13]

SP AusNet and United Energy also proposed allowances for poles and wires risks. The AER noted that SP AusNet had removed the costs incurred from 2009 poles and wires events from the base year. However, the AER in the draft decision rejected United Energy and SP AusNet's proposed poles and wires self insurance amount on the basis that they are relatively small and would be likely outweighed by the upside risks.[14]

[8] ibid, p. 253.
[9] The AER also noted that there may be some pole fire costs already contained in JEN's capex forecasts, see AER, *Draft decision*, appendix M, p. 256.
[10] AER, *Draft decision*, appendix M, p. 256.
[11] ibid, p. 257.
[12] ibid, pp. 259- 260.
[13] AER, *Draft decision*, appendix M, pp. 259-260.
[14] ibid, pp. 258-259.

Contaminated land risk

The AER, in its draft decision rejected United Energy's proposed self insurance allowance for contaminated land risk. The AER considered these to be maintenance costs of a non-routine nature, for which an allowance was provided in United Energy's forecast opex. The AER further noted that these costs would otherwise be rejected on the basis that they are relatively small and would therefore likely to be outweighed by the upside risks faced by the DNSPs'.[15]

Environmental risk

The AER, in its draft decision rejected United Energy's proposed self insurance allowance for environmental risk. The AER noted United Energy had not provided any clear reasoning for why it was proposing a self insurance allowance. The AER further noted that these costs would otherwise be rejected on the basis that they are relatively small and would be therefore likely to be outweighed by the upside risks faced by the DNSPs'.[16]

Insurer default risk

The AER rejected self insurance allowances for insurer default risk. This self insurance allowance was proposed by SP AusNet and United Energy on the basis that this risk was permitted as a pass through in the draft decision (and hence recovered elsewhere in the regulatory regime). That is, the AER permitted these costs as a nominated pass through event in the draft determination.[17]

Motor vehicle risk

The AER rejected CitiPower and Powercor's proposed self insurance allowances for motor vehicle risk on the basis that these risks have been compensated through CitiPower and Powercor's forecast opex for the 2011–15 regulatory control period. That is, a representative amount was already in the base year.[18]

Fraud risk

The AER rejected SP AusNet and United Energy's proposed self insurance allowance for fraud risk, noting both DNSPs had no historical fraud losses and that any risk faced by either DNSP would be too small to calculate. The AER further noted that these costs would otherwise be rejected on the basis that they are relatively small and would be therefore likely to be outweighed by the upside risks faced by the DNSPs[19].

The amounts approved for each Victorian DNSP for self insurance in the AER's draft decision are set out in the tables below.

[15] ibid, p. 260.
[16] ibid, pp. 260-261.
[17] ibid, p. 261.
[18] ibid, p. 261.
[19] AER, *Draft decision*, appendix M, pp. 262-264.

Table M.1 AER's draft decision on CitiPower's self insurance allowance 2011–15 ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability	2.72	0
Motor vehicle	0.32	0
Property	1.82	0
Total	**4.86**	**0**

Table M.2 AER's draft decision on Powercor's self insurance allowance 2011–15 ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability	12.18	0
Motor vehicle	1.70	0
Property	2.33	0
Total	**16.21**	**0**

Table M.3 AER's draft decision on JEN's self insurance allowance 2011–15 ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Substations—catastrophic or component failure	1.028	0
Other assets—storms and lightning	0.552	0
Other assets—pole fires	0.036	0
Damage to third party property	0.167	0.167
Public liability—fatality	0.051	0.051
Public liability—injury	0.304	0.304
Total	**2.669**	**0.522**[a]

(a) An allowance of $104 300 per year of the regulatory period

Table M.4 AER's draft decision on SP AusNet's self insurance allowance 2011–15 ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability—general	8 022	0
Bushfire	3 558	0
Poles and wires	9 100	0
Insurer default	0.157	0
Fraud	0.044	0
Total	**20.880**	0

Table M.5 AER's draft decision on United Energy's self insurance allowance 2011–15 ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability —general	0.535	–
Liability—fire	0.245	–
Liability—asbestos	0.120	0.12
Poles and wires	2.710	–
Fraud	0.015	–
Insurer's default	0.125	–
Property	13.750	–
Contaminated land	2.380	–
Environmental	0.220	–
Total	**20.030**	**0.12**[a]

(a) An allowance of $24 000 per year of the regulatory period.

M.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor and JEN accepted the AER's draft decision on self insurance, and incorporated the appropriate figures into their revised regulatory proposals.[20]

In its revised regulatory proposal, United Energy stated that it did not accept the AER's findings in relation to self insurance allowances. Further, it did not agree with the AER's rejection of costs on the basis that they were 'relatively minor'. United Energy stated:

> It is also implicit in the reasoning presented in the Draft Decision that the AER would reject the proposed self-insurance amounts on the grounds of immateriality and symmetry even if UED provided further information to support its original Regulatory Proposal. This approach is particularly disappointing, and UED believes that the AER should reconsider its decision and reasoning in relation to this issue. UED would be pleased to provide further substantiation to the AER to justify UED's self insurance costs if the AER indicates a willingness to consider the submission on its merits. UED will make a further submission to the AER in relation to this issue. For the purposes of this Revised Regulatory Proposal, however, UED stands by its original submission.[21]

SP AusNet did not accept the AER's decision to reject self insurance allowances for liability and poles and wires risks.[22]

In relation to liability risks, SP AusNet noted that the AER had effectively split the analysis into two components; general liability risks, and fire liability risks.

SP AusNet made the following arguments in relation to liability risks:

- The AER erred in stating that, where an event occurred in the base year, a representative amount was already captured in the opex allowance. SP AusNet asserted that it had clearly stated (in its original proposal) that such costs were excluded from the base year for poles and wires risk, and hence compensation was required for them through self insurance.[23]

- The AER's approach incorrectly assumes that one data point - represented by actual costs incurred in 2009 - is a better reflection of future expected costs that a prudent and efficient provider may incur in the forthcoming regulatory control period, than that which would be calculated through the use of a longer data series reflecting historical expenditure. SP AusNet noted that this is especially inappropriate for liability risks as they are materially volatile. This demonstrates a need to apply a statistically robust approach, which uses as many data points as possible.[24]

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[20] CitiPower, *Revised regulatory proposal 2011 to 2015*, July 2010, p.33; JEN, *Revised regulatory proposal, July 2010*, pp. 124-125; Powercor, *Revised regulatory proposal 2011 to 2015*, July 2010, p. 167.

[21] United Energy, *Revised Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015*, July 2010, pp. 98-99.

[22] SP AusNet, *Electricity Distribution Price Review 2011-2015 revised regulatory proposal*, July 2010, pp. 255-257.

[23] ibid, pp. 255-257.

[24] ibid. pp. 255-257.

- The AER has not explained why the use of one data point (2009) is considered to be a more robust predictor of liability costs that a prudent and efficient business would occur.[25]

SP AusNet also stated that the full costs of the 2009 bushfire were not available at the time of preparing the revised regulatory proposal.[26] SP AusNet proposed a revised assessment of self insurance allowances for the forthcoming regulatory control period for liability risks of $3.47m.[27]

SP AusNet did not accept the AER's draft decision on poles and wires risk. SP AusNet did not agree with the AER's statement that these costs are 'relatively minor', and contended that the AER's assertion that there are counteracting 'upside risks' was unrealistic and unsubstantiated.[28] SP AusNet stated that this approach leads to an inconsistent treatment of self insurance proposals (citing the AER's draft decision in which the AER provided United Energy with a $24 000 per annum self insurance allowance for asbestos liability, despite this amount being less than SP AusNet's proposed allowance for poles and wires risk). SP AusNet stated that the AER's refusal to provide an allowance for poles and wires was inconsistent with s. 7A of the NEL. That section specifies that a service provider should be provided with a reasonable opportunity to recover at least its efficient costs. In light of this, SP AusNet retained its proposed self insurance allowance for poles and wires risk of $8.9m over the forthcoming regulatory control period in its revised regulatory proposal.[29]

SP AusNet noted that the AER in the draft decision rejected the self insurance allowance for insurer credit risk. SP AusNet stated that it may still face asymmetric downside risk given the magnitude of the AER's proposed one percent materiality threshold. SP AusNet proposed a reduction in the AER's materiality threshold for this event (refer to chapter 16 for AER's consideration of this issue).[30]

SP AusNet accepted the AER's rejection of fraud risks.[31]

M.3 Submissions

No submissions were received on self insurance.

M.4 Issues and AER considerations

At the outset, the AER notes that its approach to assessing self insurance must be in accordance with the requirements in clause 6.5.6 of the NER. This is because self insurance is a component of opex. A detailed analysis of the AER's approach to total

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[25] ibid., pp. pp. 255-257.

[26] In the draft decision, the AER stated that it would review SP AusNet's 2009 bushfire actual incurred costs to quantify and calculate the appropriate self insurance costs for a 1 on 20 year event. SP AusNet noted that it could take up to 5 years to finalise the costs of this event. SP AusNet did, however, note that it had provided information to the AER on costs so far incurred from the 2009 bushfires.

[27] SP AusNet, R*evised regulatory proposal*, July 2010, pp. 255-257.

[28] ibid., pp. 258- 259.

[29] ibid, pp. 258- 259.

[30] ibid, pp. 258- 259.

[31] ibid., p. 260.

opex is set out in chapter 7 of this final decision. However, it is useful to summarise that approach here so that the role of self insurance in the regulatory regime can be fully understood.

The AER considers the base year (usually the penultimate year of the present regulatory period) costs as a starting point for forecasting opex. This is because it is reasonable to assume that the costs of meeting the opex objectives (as set out in clause 6.5.6(a) of the NER) are at least partly captured in the DNSP's current operating environment. The AER then considers what additional allowances should be provided to DNSPs so that they can meet changing circumstances that they may face in the forthcoming regulatory control period. Step changes are the primary vehicle for doing this (these broadly provide allowances for changed regulatory obligations, or changes to the operating environment).

However, to acknowledge for risks that may be faced by the DNSPs (which are not recovered elsewhere), the AER provides a self insurance allowance. As a starting point, the AER first considers whether or not these costs are recovered elsewhere within the regulatory regime. Other areas where cost recovery may be provided include:

- capex,
- the pass through mechanism, and
- the WACC.

Self insurance serves to provide allowances for risks which are not incurred in a consistent or predictable manner over time. These can be risks which have been historically incurred risks, or they can be risks that the DNSP expects to face in the future. The timing of these cost is often not known in advance, hence the service provider 'self insures' for them. For risks that have been historically incurred, the common method of calculating self insurance premiums is by undertaking a 'loss times probability' calculation.

The AER considers that this approach assists in its determination of whether it can be satisfied that the forecast opex reasonably reflects the opex criteria. The AER notes that this approach, apart from being accepted regulatory practice, is permitted under clause 6.5.6(e)(5) of the NER. (The AER must have regard to opex factors in determining whether forecast opex reasonably reflects the opex criteria in clause 6.5.6(c) of the NER.) Where a DNSP has historically faced a risk and it is not evident that that risk is increasing over time, then a further allowance for self insurance is not necessary.

The above approach has also been implicitly accepted by the Victorian DNSPs. Consultants' reports provided by each DNSP have calculated self insurance allowances on this premise. It is also the reason why the AER tends not to accept self insurance allowances for costs which have not been historically incurred. Such costs are better considered as opex step changes — which acknowledge changing circumstances or regulatory obligations/requirements faced by the DNSP.

The NER requires the AER to be satisfied that the forecast opex meets the opex criteria.[32] Accordingly, in its assessment of self insurance opex, the AER considers whether such opex reasonably reflects the expectation of cost inputs required to achieve the opex objectives (clause 6.5.6(c)(3)). The DNSP has a variety of mechanisms to mitigate or protect itself against risks. One primary tool for doing so is external insurance for which the AER provides an allowance (see appendix L). Most external insurance policies carry an accompanying excess or deductible —the component which the DNSP must contribute to a claim made on that policy. In this context, the AER permits self insurance allowances for these costs in accordance with clause 6.5.6(c)(3).

The AER further considers that its approach to self insurance opex is consistent with the opex criterion in clause 6.5.6(c)(1) of the NER: *the efficient costs of achieving the opex objectives*. To disallow insurance deductibles would incentivise the DNSP to insure for the entire risk. This would lead to substantially higher premiums (as the willingness of the DNSP to bear some risk significantly reduces the premium charged by the insurer). The commensurate premiums would then be passed onto customers. The AER considers that it is more efficient for consumers to fund a self insurance allowance. The AER may not allow self insurance allowances for below deductible costs where the DNSP has already paid those deductibles in its base year (see, for example, the risks rejected in the AER's draft decision, summarised in section M.1 above).

Further, the AER considers that self insuring for below deductible amounts is consistent with the amounts incurred by a prudent and efficient operator (clause 6.5.6(3)(c)(1) and (2) of the NER). This is because the AER considers that is it more cost efficient for the DNSP to retain some risk on external insurance policies than, for example, insuring for the entire risk. This would lead to inefficient increases in premiums.

The AER also considers the risk faced by the DNSPs in the context of the opex objectives such as the objective contained in clause 6.5.6(a) (1) of the NER —that is, the costs of meeting or managing the expected demand for direct control services. The AER also considers what a prudent operator would require to achieve this objective (clause 6.5.6(c)(2) of the NER). By providing an allowance for risks which are faced by a prudent DNSP, that is, downside risks which are not compensated for elsewhere in the regulatory regime, the AER is providing for the efficient recovery of costs consistent with what would be incurred by a prudent operator. To provide allowances for risks which are compensated through other areas of the regime would lead to an effective double recovery of costs. This, in turn, would be inconsistent with the aforementioned opex objectives and the incentive regime more generally.

The AER has, in determining whether it is satisfied that DNSPs' forecast opex (as it relates to self insurance) reasonably reflects the opex criteria, had regard to various opex factors, including those outlined above. The AER has also considered the information contained in, or accompanying the regulatory proposals (clause 6.5.6(e)(1) of the NER). Further, for some risks, the AER has undertaken its own analysis (clause 6.5.6(e)(3)) in forming a view on the appropriate self insurance

[32] Clause 6.5.6(c).

amounts that a prudent and efficient operator requires to meet or manage expected demand over the forthcoming regulatory control period.

M.4.1 Asymmetric downside risks and rejection of United Energy's proposed risks

M.4.1.1 AER draft decision

The AER, in its draft decision, noted that self insurance allowances should be provided for asymmetric downside risks in aggregate (on the basis that these risks can be quantified through loss history).[33] Put differently, these risks are risks that are not compensated for through upside risks faced by network service providers. The AER further noted that the information asymmetry problem (that exists between the DNSPs and regulators) makes it difficult to quantify and assess these upside risks. It was on this basis that the AER rejected several proposed allowances, particularly risks proposed by United Energy such as:

- fraud risks
- poles and wires risk
- contaminated land risk
- environmental risks.[34]

M.4.1.2 Victorian DNSP revised regulatory proposals

Both United Energy and SP AusNet disagreed with the AER's assertion that some costs were 'relatively minor'. SP AusNet further contended the AER had not quantified these upside risks, or outlined what these risks were.[35]

United Energy also disputed that its self insurance allowances were relatively minor. United Energy stated that it maintains its original proposal in relation to self insurance. United Energy stated that its regulatory proposal included self-insurance items that totalled approximately $20 million over the forthcoming regulatory period. United Energy considered that this amount was not small. United Energy further asserted that the NER and NEL do not allow the AER to reject cost forecasts on the grounds that the forecast amount is relatively small.[36]

M.4.1.3 Issues and AER considerations

The AER maintains its draft decision position on asymmetric risks. However, the AER considers that based on the Victorian DNSPs' revised proposals that there may be some misunderstanding about how the AER has assessed the proposed self insurance allowances. The AER considers that the rejection of self insurance allowances for risks which are not negatively asymmetric in aggregate is consistent with the opex criteria, for example the criterion in clause 6.5.6(c)(3) of the NER. Compensation for such risks is not consistent with a realistic expectation of the

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33 AER, *Draft decision*, appendix M, p. 249.
34 ibid, pp. 259-262.
35 SP AusNet, *Revised regulatory proposal*, July 2010, p. 259.
36 United Energy, *Revised regulatory proposal*, pp. 97-99.

demand forecast and cost inputs required to meet the operating expenditure objectives.

In response to SP AusNet (which raised issues with the AER's acceptance of United Energy's asbestos compensation allowance), the AER notes that the AER accepted these costs because they related to a below deductible amount for an external insurance policy. The AER in the draft decision accepted the below deductible amounts as self insurance allowances on the basis that it would not be economic for DNSPs to seek insurance for below deductible amounts. The AER considers that this approach incentivises the DNSPs to seek the economically efficient amount of insurance coverage. The AER's reasons for providing below deductible insurance amounts, and how doing so is consistent with cl. 6.5.6, are set out above. United Energy's asbestos compensation risk related to a cost input to achieving the opex objectives (clause 6.5.6(c)(3) of the NER)—that is, a deductible amount. Further, this cost input was not already captured in the base year. Accordingly, the AER accepted United Energy's below deductible amount of $24 000 per annum related to insurance for asbestos risk.

In relation to the other risks proposed by United Energy in its revised regulatory proposal, the AER maintains its view that the allowances proposed by United Energy are not consistent with clause 6.5.6 of the NER. That is:

- For below deductible amounts on external policies for general liability—although these relate to a cost input under clause 6.5.6(c)(3) of the NER, the AER notes that commensurate amounts were captured in United Energy's 2009 base year. Put differently, the AER has rejected these costs on the basis that United Energy already has appropriate cost inputs to meet the opex objectives in 6.5.6(a) of the NER. In coming to this view, the AER has considered the opex factors in clause 6.5.6(e)(1) and (5) of the NER.

- For poles and wires risks — although these relate to a cost input under clause 6.5.6(c)(3) of the NER, the AER notes that commensurate amounts were captured in United Energy's 2009 base year. Similar to the reasoning in the preceding paragraph, the AER did not accept these costs as United Energy already has appropriate cost inputs to meet the opex objectives. The AER also had regard to the opex factors in clause 6.5.6(e)(1) and (5) of the NER.

- For property risks — the AER considers that an allowance for these costs is not necessary under the broader opex allowance as these costs are capitalised and are hence recovered elsewhere — that is, they are recovered through the RAB. The AER has had regard to the opex factors, in particular, clause 6.5.6(e)(1) and (3) of the NER.

- For contaminated land risk —the AER considers that this allowance has already been recovered elsewhere in the regulatory regime - and hence, these are not efficient costs under clause 6.5.6(c)(1) of the NER. The AER has had regard to the opex factors, specifically, clause 6.5.6(e)(1) and (3) of the NER.

- For environmental risks, fraud risks and insurer credit default risks— these costs are not based on a 'loss times history consequence.' United Energy considered that they should be placed on 'reserve' if it needs to respond to this risk in the 2011-2015 regulatory control period. The AER considers that United Energy has not provided evidence that this cost will be incurred during the forthcoming regulatory control period, and thus this cost cannot be considered a cost input required to meet the opex objectives (see clauses 6.5.6 (c)(3) and 6.5.6(a) of the NER). In relation to the insurer credit risk, the AER notes that this is an additional pass through event in this final decision. Further discussion of pass through is in chapter 16 of this final decision, and in section M.4.4 of this appendix below.

The poles and wires risk proposed by SP AusNet in its initial regulatory proposal did not appear to relate to below deductible amounts. Further discussion on the SP AusNet poles and wires risk is set out below.

M.4.1.4 AER conclusion

In assessing proposed self insurance premiums (that is for amounts above deductibles on insurance policies) the AER will only permit compensation for risks that are in accordance with clause 6.5.6 of the NER. The AER considers that such risks are those that represent cost inputs such as insurance deductibles required to meet the opex objectives (clause 6.5.6(c)(3) of the NER) which are incurred by a prudent and efficient operator (clause.6.5.6(c)(1) and (2) of the NER) and which are not captured in a DNSP's base year (clause 6.5.6(e)(5) of the NER).

Accordingly, the AER maintains the assessment of United Energy's self insurance risks as set out in the draft decision (that is, to reject all risks on the grounds that they are outweighed by upside risks, except for asbestos liability, which the AER allows $24 000 per annum for below deductible amounts). The AER also maintains its view that that the other risks proposed by United Energy in its initial regulatory proposal are outweighed by upside risks inherent in the regulatory regime.

M.4.2 Poles and wires risk

M.4.2.1 AER draft decision

The AER rejected the proposed poles and wires risk allowance proposed by SP AusNet in its draft decision. In doing so, the AER stated:

> The Aon report for SP AusNet cited bushfire events in February 2009 as an example of damage to poles and wires. SP AusNet, in its regulatory proposal, states that it has removed poles and wires expenditure incurred in 2009 from its base year. Whilst the AER accepts that this may be the case (and acknowledges that these costs are not capitalised), the AER considers that they are relatively minor when compared to the upside risks faced by the DNSPs. That is, the upside risks would outweigh the negative risks, such that there is unlikely to be net asymmetric downside risk to be compensated by a self insurance allowance. The AER therefore rejects SP AusNet's proposed self insurance allowance for damage to poles and wires, and replaces it with an allowance of $0.[37]

M.4.2.2 Victorian DNSP revised regulatory proposals

SP AusNet's proposed poles and wires risk of $1.77m to $1.79m per annum was estimated from SP AusNet's loss history and adjusted upwards by SP AusNet for

[37] AER, D*raft decision*, appendix M, p. 258.

expected annual increases in line length (a total of approximately $8.89m over the forthcoming regulatory control period). [38]

SP AusNet disagreed with the AER's draft decision to reject these costs. It reiterated that it had excluded these costs from its base year calculation (and hence, a representative amount is not in the base year). It disputes the AER's reliance on 'upside risks', stating the AER had not provided evidence of these alleged upside risks, and had not outlined these events at a qualitative level. SP AusNet stated that, if the AER maintained its rejection of the proposed annual allowances for poles and wires risks, the AER should increase SP AusNet's base year by $8.6m.[39]

M.4.2.3 Issues and AER considerations

The AER notes the arguments put forward by SP AusNet in relation to poles and wires risk.[40] In particular, the AER notes (in its assessment of the opex factor in clause 6.5.6(e)(5), which directs the AER to consider historical expenditure) that SP AusNet has excluded incurred costs for poles and wires risk from its base year (a total of $8.6m).

The AER further notes that, according to the Aon report provided with SP AusNet's revised regulatory proposal, these costs relate to maintenance for poles and wires, and hence are not capitalised and recovered through the RAB.

On this basis, the AER recognises that these costs are not recovered elsewhere through the regulatory regime. It is therefore reasonable that some allowance should be provided to SP AusNet for poles and wires risk. It is further reasonable to assume that a loss times consequence calculation should be used to determine the appropriate amount for that allowance.

In assessing the appropriate amount of that allowance, the AER has considered each opex criterion, particularly the likely risk and consequential costs that SP AusNet will face in relation to poles and wires maintenance, that is, whether the forecast opex reasonably reflects a realistic expectation of the cost inputs (and demand forecasts) required to achieve the opex objectives (clause 6.5.6(c)(3) of the NER).[41] In forming its view on the efficient amount of that cost input, the AER has had regard to the opex factors, particularly, the information accompanying SP AusNet's revised regulatory proposal (the Aon report, which calculates estimated self insurance allowances on a loss history basis), and the AER's analysis of that report.[42]

For poles and wires risks, the Aon report refers to seven years of loss history, from 2003-2009. The report contains details of what costs were incurred by SP AusNet in each year of that loss history. The data set indicates that the 2003-2009 costs were used as a basis for severity distributions for both storm and bushfire risks.[43] The Aon

[38] SP AusNet, *Revised regulatory proposal*, p. 260.
[39] ibid, p. 261.
[40] SP AusNet, R*evised regulatory proposal*, July 2010, pp. 258.
[41] In particular, the AER has had regard to the opex objective in clause 6.5.6(a)(1) of the NER, the opex to meet or manage the expected demand for standard control services.
[42] Clause 6.5.6(e)(1) and (3) of the NER, respectively.
[43] Aon, *Self insurance risk quantification SPI Electricity Pty Ltd* , July 2010, p. 11.

report noted that detailed operation expenses for events prior to 2003 were not available.[44] The losses, as per that report, are:

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It is worth noting that most consultants' reports submitted by most DNSPs as part of this determination calculates self insurance allowances by reference to loss history. As noted in section M.4 above, this is an industry accepted practice. In calculating these allowances, risk consultants generally total historical losses over time, and then divide those losses over the data set (for example, a historical total loss for a particular risk of $20 million over twenty years would carry a forward looking self insurance allowance of $1 million per annum). This can be referred to as a 'baseline' allowance for that risk. Provided there is consistency in data collection and a reasonable data set, the AER accepts this method of calculation by risk consultants'.

However, the AER notes that another practice is often added to this process —that is, the practice of providing an 'uplift' to that allowance, which seeks to compensate the DNSP for significant one-off events. This involves some estimation of what sorts of costs those events might carry, because these events have often not occurred in recent history. These events are traditionally not captured in the historical data set but their potential cost impacts are substantial and it is reasonable for an allowance to be provided for them.

The AER considers that the 2009 bushfire event is an example of such an event. The costs associated with this event are substantial and affect several areas of the DNSP's expenditure profile. In the context of self insurance, two further examples are 'poles and wires risks' and 'liability risks'. Liability risks are discussed in more detail at section M.4.3 below. It is also worth noting that an 'uplift' to liability self insurance allowances has been traditionally provided to DNSPs.

The Aon report did not provide any such 'uplift' for SP AusNet's poles and wires risk. However, it did acknowledge that the 2009 incurred costs of $8.6m (which were included in the calculation of the self insurance allowance) were significant and are costs that could be characterised as emanating from a one in twenty year event. That is, they are extreme costs, the calculation of which has normally been an estimate at best, and only apportioned a one in twenty year weighting.[45]

However, because only seven years of data history is available, the 2009 incurred costs —which are consistent with a one in twenty year event — have effectively been given a one in seven year weighting.[46] The AER considers this weighting to be disproportionate with the actual risks faced by SP AusNet. If a longer data set was available, then the cost impact of the 2009 bushfire would not have such a substantial impact on the mean costs over time. However, because only seven years of data has been used, the cost impacts from 2009 have been overrepresented. The variability in the costs above clearly shows the volatility associated with poles and wires risk incurred by SP AusNet.

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44 ibid., p. 11.
45 ibid.
46 ibid, p.11.

However, the AER accepts that further loss history may not be available for SP AusNet, and that the calculation of an allowance for poles and wires risk is limited to cost history from 2003 to the present time.

Noting that a one in twenty year event can now be quantified for this risk, the AER considers that a more appropriate way to provide an allowance for this cost input is to provide a 'baseline' for the 2003—2008 period, and provide an 'uplift' for the poles and wires costs associated with a one in twenty year event (that is, 2009). To apply a proportionate weighting to the costs from 2009, the AER has totalled the poles and wires costs incurred in that year (from the bushfire event) and divided these costs by twenty.

This is consistent with Aon's methodology for providing an uplift for other extreme events.[47] The cost impact of the bushfire on poles and wires was $8.7 million.[48] Therefore, dividing that by twenty, the appropriate amount to compensate for extreme one in twenty year events that impact upon poles is $436,645.[49] This amount should be added to the 'base amount' calculated above, that is, the average of the years 2003—2008.

The AER has taken a historical loss/consequence calculation of the years 2003—2008. This is consistent with Aon's methodology. This can be considered as a 'base amount' for the self insurance premium for poles and wires risk. Although the data set shows volatility in costs, the average costs from these years appear to represent what could be discerned as a 'typical' cost outcome from a poles and wires risk event(s). This calculation produces a base self insurance amount of approximately $863,467.[50] This is the average incurred cost from 2003-04—2008-09.

In summary, the AER has determined that SP AusNet's forecast costs for poles and wires risks do not reasonably reflect the opex criteria. The AER has determined that the appropriate amount for this risk is $1.3 million (that is, the addition of the 'baseline' amount and the 'uplift' amount). In forming this view, the AER has had regard to the opex factors in clause 6.5.6(e)(1) and (3) of the NER, specifically, the Aon report submitted by SP AusNet and the AER's own analysis.

M.4.2.4 A.4.2.4 Conclusion

The AER rejects the proposed self insurance premium, and replaces it with a revised self insurance premium for SP AusNet, that is, $1.3m per regulatory year of the regulatory control period.

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47 See for example, Aon's methodology for the uplift for liability self insurance allowances. In that calculation, they assumed the cost impact to be $10 million -that is, the full cost of SP AusNet's insurance deductible - and divided it by 20. This derived an annual amount to compensate SP AusNet for extreme one in twenty events. This amount then had escalators applied to it, for customer growth. See pp 7-8 of the Aon report.

48 Aon report, appendix 2, attachment 1. This amount is slightly higher than the amount taken out of SP AusNet's base year, as Aon has adjusted this amount for CPI .

49 That is, $8 603 844 divided by 20.

50 That is, $5 180 802 divided by 6, with 2009 costs excluded,

M.4.3 Liability risks

M.4.3.1 AER draft decision

The AER's draft decision rejected SP AusNet's proposed costs for liability risks. On bushfire liability, the AER stated:

> The AER notes that a 'major' fire event (that is, an event that may be described as a 'one in twenty year' event) has already occurred on SP AusNet's network, in February 2009. The policy deductible for bushfire claims is $10 million. Aon asserts that for a one in twenty year event, SP AusNet would incur that total cost of the deductible (that is, the liability would be beyond $10 million). However, the AER notes that the liability quantified so far (as at July) for 2009 is only at $1 963 637. The full cost of liabilities arising from the February 2009 bushfire event are yet to be quantified. The AER considers that the full costs should be representative of a major fire event and a forward looking self insurance allowance can be based on those losses. As a result, once costs have been quantified (the AER expects that this will happen as part of SP AusNet's revised regulatory proposal, and as the actual costs for 2009 will form the base year for the purposes of forecasting opex over 2011–15), the AER can make an assessment of the actual cost impacts of such an event, and determine an appropriate self insurance allowance for the deductible (if any) to compensate for any future events.[51]

In relation to general liability, the AER stated:

> For general liability, the AER notes that the incurred annual losses over the current regulatory control period (2006–10) that the DNSPs have covered through their opex allowance, are representative of future expected losses (apart from 2009 bushfire losses for Powercor and SP AusNet, which the AER will assess as part of its final distribution determination). The historical losses are recurrent and have been included in the DNSPs' base year opex. The AER does not consider it necessary to allow additional compensation for these risks. Accordingly, the AER rejects the general liability allowances for Powercor, SP AusNet and United Energy, and replaces them with $0.[52]

M.4.3.2 Victorian DNSP revised regulatory proposals

The AER notes that SP AusNet's revised regulatory proposal estimated costs of $3.47m for liability risks (that is, including general liability and bushfire liability risk).[53] SP AusNet's estimate of general liability risks (which includes bushfire liability) was based on the quantifications undertaken by Aon for liability risks, which calculated annual allowances of **[text removed CIC]** adjusted upwards annually by SP AusNet for its expected annual growth in customers (a total of approximately **[text removed CIC]** over the forthcoming regulatory control period).[54]

The AER notes that the difference between the revised regulatory proposal amounts and the amounts sourced from the Aon report, including SP AusNet's adjustments to

[51] AER, *Draft decision*, June 2010, Appendix M, p. 255.
[52] ibid, p. 255.
[53] SP AusNet, *Revised regulatory proposal*, p. 260.
[54] Aon, *Self insurance quantification report, SPI Electricity,* July 2010 pp. 7-9.

these amounts for expected customer growth and line length), represent costs that SP AusNet submitted are already included in its base year.[55]

SP AusNet was critical of the AER's draft decision on liability risks. First, SP AusNet rejected the AER's assertion that a representative amount for general liability was already captured in the base year.[56] Second, it stated that the AER has incorrectly assumed that one data point - actual 2009 data costs - are a better reflection of the future expected costs over the forthcoming regulatory control period. SP AusNet noted that liability risks are particularly volatile.[57] SP AusNet also noted that the AER failed to explain why it rejected Aon's quantification of risks (since it appeared to accept the methodology).

On bushfire liability, SP AusNet provided an updated quantification of risks, which removed Aon's climate change adjustment. In relation to the AER's draft decision consideration of one in twenty year events, SP AusNet stated that:

> The AER's statement suggests that SP AusNet will have access to information regarding the full costs associated with the 2009 bushfire…
>
> information regarding the full costs of this event are unavailable at present. This situation is consistent with experience from other events of this magnitude (such as the Ash Wednesday and Canberra bushfires in relation to which it took up to 5 years to finalise matters arising from these events)…
>
> SP AusNet has provided confidential information to the AER regarding costs incurred so far in relation to the 2009 bushfires, and writs against SP AusNet in relation to the event. SP AusNet considered that this approach will provide the AER with the best information available this time… it is noted that all bushfire related costs have been treated as non-recurrent items, and therefore, they have removed from the base year. [58]

M.4.3.3 Issues and AER considerations

In forming a general view on whether or not an allowance should be provided for this risk, the AER notes that it considers below deductible amounts for insurance policies to be an acceptable cost input incurred by a prudent and efficient operator (clause 6.5.6(c) of the NER). More detail on the AER's on reasoning as to why this is a relevant cost input is contained in section M.4 above. The appropriate amount for that cost input has been assessed in line with the Aon report provided by SP AusNet, and the AER's own analysis, set out below.

SP AusNet stated that the AER has not provided any analysis to refute Aon's methodology and that in the absence of such analysis, it inferred that the AER had accepted the method of calculating self insurance allowances for liability risks. The AER notes that SP AusNet's proposed self insurance allowance in its revised regulatory proposal is based on the updated report.

The AER initially sought to use 2009 actual costs for self insurance for liability risk. The AER considered that a representative amount for these risks was already

55 SPA_O&M Forecasts_Final.xls
56 SP AusNet, R*evised regulatory proposal*, July 2010, p. 259.
57 ibid, p. 259.
58 ibid, p. 259.

contained in the base year and that the amount there reasonably reflected an estimation of SP AusNet's risk in the forthcoming regulatory control period.

The AER accepts that Aon has used a loss history/consequence times probability methodology to calculate self insurance allowances for SP AusNet. The AER agrees in principle with this approach, but notes that there are a number of areas in which the Aon report lacked transparency. For example, Aon does not specify why it considers that years 2001-2009 'best represent' SP AusNet's likely future loss experience.[59] Further, the AER notes that there is no explanation for the following statement in the Aon report:

> This is likely the result of more accurate record keeping in recent years and/or a change in exposure resulting in earlier years not reflecting the degree of risk now faced.[60]

While the costs from 2001-2009 (relating to liability losses) are higher, on average, than previous years (ranging, from [**text removed CIC**] in the years from 1990-2000, and [**text removed CIC**] in the years from 2001-2009), the AER considers that, where a longer data set is available, it should be used to calculate self insurance premiums. Indeed, this appears to be consistent with SP AusNet's comments on liability history. As SP AusNet noted in its revised regulatory proposal:

> Historical data show that the outturn costs for this risk are materially volatile, and that this reinforces the need for a statistically robust approach, which uses as many data points as are reasonable available to derive a robust estimate.[61]

The AER concurs with this statement. It notes that SP AusNet has 21 years (1990-2010) of liability loss data that is available (including fire liability).[62] The incurred loss history over that time totals approximately [**text removed CIC**. Aon notes that the average loss history for 2001-2009 (as calculated by Aon and used as a basis for SP AusNet's proposed self insurance premium) is [**text removed CIC]**.[63] The AER does not consider that there are any in principle issues with the method of this calculation. However, the AER considers that a more appropriate allowance would be the average general liability over a longer year loss history, rather than the nine years from 2001 to 2009. This is in line with SP AusNet's assertion that, due to the volatility of liability claims history, a longer data set should be used. That said, while Aon has not substantiated that the relevant time period for estimating future losses is 2001-2009, the AER notes that the number of loss events prior to 1997 is significantly lower. Accordingly, the AER has considered SP AusNet's loss history from 1997 to 2009 - this results in an average loss of $1.38m [64]

SP AusNet's revised proposal indicated that the full costs of the 2009 bushfires cannot be known at this time, noting that it can take up to five years to fully quantify the incurred costs.[65] As part of its revised regulatory proposal, SP AusNet provided

59 Aon, *Self insurance quantification report, SPI Electricity,* July 2010 p. 7.
60 Aon, *Self insurance quantification report, SPI Electricity,* July 2010 p. 7.
61 SP AusNet, *Revised regulatory proposal,* p. 256.
62 Aon, *Self insurance quantification report, SPI Electricity,* July 2010, Appendix 1, attachment 1.
63 ibid., pp. 7-9.
64 That is, $19 846 243 divided by 21.
65 SP AusNet, *Revised regulatory proposal,* p. 258.

incurred costs to date, and copies of writs against it in relation to the 2009 bushfires.[66] On the costs incurred to date it appears from Aon's report that these costs were also considered by Aon in its updated report to derive its proposed self insurance allowance.

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Aon also adjusted upwards the average annual loss history of [**text removed CIC]** over the period of 2001-09) for a one in twenty year event by $0.47m to derive its proposed allowance of [**text removed CIC**] for liability risks.[67] That is, Aon appeared to take a 'baseline' liability over the eight years of data, and then provide an 'uplift' to compensate for one in twenty year events. That uplift was based on the assumption that, once in each twenty year period, an extreme event would occur and incur costs of $10 million (that is, the insurance deductible for liability that SP AusNet must pay in the event of a fire claim).[68] Aon also considered that this amount should increase over time on the basis that SP AusNet's exposure will increase over time where SP AusNet's will experience 'more of the same losses'. The AER notes that Aon applied customer number growth to the growth in estimated losses.[69]

Fire liability - one in twenty year event

The AER, in its draft decision, did not accept the inclusion of this additional allowance for a one in twenty year event. The AER acknowledged that a major fire event could occur once every twenty years. However, the AER noted that it was not certain that a one in twenty year event would necessarily incur a $10 million cost.[70] The AER notes that at this stage, it seems uncertain whether SP AusNet would incur the entire cost of the deductible as a result of a one in twenty bushfire event. The AER, as previously discussed, considers that a self insurance allowance should be based on objective data (which includes a DNSP's available loss history) to calculate probability times consequence. Accordingly, the AER indicated in the draft decision that in quantifying a proposed self insurance allowance for such an event it would consider further information regarding the actual costs of the 2009 bushfire. The AER assumed that such an event could satisfy the 'one in twenty' year probability and therefore the actual costs could be considered to be representative of a one in twenty year event. That said, the AER also acknowledges that the 2009 bushfires may be more representative of a lower probability than a one in twenty year event (for example a 1:50 year event) that may lower any self insurance allowance.

[66] See Letter to A Watson, provided confidentially with SP AusNet's revised proposal.

[67] Aon appendix 1 , attachment 2

[68] Aon report, pp. 7-9.

[69] ibid., p. 18

[70] AER, *Draft decision*, Appendix M, p. 255.

In relation to the writs provided by SP AusNet, the AER accepts that costs (should actions/claims against SP AusNet be successful) may be incurred by SP AusNet in the future. However, given that these writs relate to pending legal actions, the outcomes are highly uncertain and can only be viewed as potential losses. The AER has considered 13 years of SP AusNet's loss history (1997-2009), in line with SP AusNet's regulatory proposal that a longer data set should be used (and also given that Aon did not provide adequate reasons as to why 2001-2009 is more appropriate). In forming the view on this data set, the AER notes that costs prior to 1997 (that is, from 1990) are substantially lower for liability costs incurred by SP AusNet. The AER assumes that there may be some issues with data collection, or the reliability of data prior to 1997, and therefore, may not be representative in forming an estimate of expected costs. That said the AER has used a longer data set of loss history in the final decision which is supported by SP AusNet to determine an appropriate self insurance allowance which by including 2009, the AER considers should incorporate a one in twenty year event. Further as noted above, the inclusion of 2009 data may be more than representative of a one in twenty year event such that the use of 2009 data may provide SP AusNet with a higher than representative allowance.

The AER notes that SP AusNet submitted that it has removed the 2009 actual liability costs. The AER has reviewed SP AusNet's revised regulatory proposal and notes that it submitted that $1.37m has been removed on the basis that this amount is in the base opex.[71] The AER also notes that while SP AusNet has assumed that its proposed representative annual loss will increase over time in line with customer growth, it has not assumed that the base year amount will be subject to growth over the forthcoming regulatory control period.[72] However, the AER has applied both a scale escalation factor to base opex such that any 'unfunded losses' proposed by SP AusNet will be overstated.

For poles and wires risk, the AER removed costs incurred in 2009, apportioned those costs a one in twenty year weighting, and added them to a 'base calculation' (that is, the average of the six year data set as provided by Aon). The AER did not 'carve out' the 2009 incurred costs in its liability risk calculation. This is for two reasons:

- In calculating a self insurance premium for liability risks, the AER had access to a longer data set (twenty years in total from 1990 to 2009. The AER considered that loss history from 1997 to 2009 was best representative of 'typical' risk faced by SP AusNet - a thirteen year data set in total). Therefore, the AER does not consider that the 2009 cost outcomes were given a disproportionate weight in calculating the liability premium, as the data set was considerably longer and the cost impacts from liability risks in 2009 were thus 'diluted'.

- The cost impacts from the 2009 bushfire, for liability risks, are not fully known as yet. However, the cost impacts for poles and wires risks arising from the 2009 bushfire are fully known, and can be used to calculate a standalone premium for a one in twenty year event for poles and wires risk. No such calculation can yet be made for liability risk.

71 SP AusNet, *Revised regulatory proposal;* p. 262, Ao*n report,* p. 18.
72 ibid.

In summary, the AER has determined that SP AusNet's forecast costs liability risks do not reasonably reflect the opex criteria. In forming this view, the AER has had regard to the opex factors in clause 6.5.6(e)(1) and (3) of the NER, in particular, the Aon report submitted by SP AusNet and the AER's own analysis.

M.4.3.4 Conclusion

In conclusion, the AER has not provided SP AusNet with any additional amount for self insurance given that:

- the AER considers that $1.37m (based on loss history from 1997-2009) is reflective of the amount of self insurance required (that is this includes a 1:20 loss event); and
- SP AusNet already has a representative amount in the base year opex of $1.38m (which is also escalated for network growth over time).

M.4.4 Insurer credit risk event

M.4.4.1 AER draft decision

The AER rejected this event, on the grounds that it had been included as a nominated pass through.

M.4.4.2 Victorian DNSPs revised regulatory proposal

SP AusNet stated:

> SP AusNet considers there are strong grounds for arguing that despite the existence of a cost pass through provision for certain events, the company may still face a downside asymmetric risk given the magnitude of the AER's proposed cost pass through threshold (1% of revenue). In theory, the high threshold that must be met before costs can be passed through is likely to necessitate the inclusion of a self insured risk allowance. However, in the case of insurer default, SP AusNet accepts the removal of this allowance as a result of the AER's inclusion of a pass through event for this risk. In saying this, SP AusNet has considered both:
>
> - its proposed reduction in that threshold, which mitigates any residual asymmetric risk being held by the business for this exogenous event; and
> - the fact that the scale of such an event is likely to lead to an exposure that exceeds not only SP AusNet's proposed cost pass through threshold, but also the AER's proposed threshold.[73]

M.4.4.3 AER draft decision

The AER notes that this insurer credit risk event does not relate to a below deductible amount on an external insurance policy. Further, although SP AusNet provided an Aon report that sought to quantify this risk, the AER reiterates that self insurance allowances (as opposed to pass throughs) are generally permitted for risks that can be calculated using loss history. Pass throughs are permitted for events that (amongst

[73] SP AusNet, *Revised regulatory proposal,* pp. 259-260.

other things) cannot have their timing or cost impact determined in advance. Although SP AusNet states that the threshold is too high, the AER maintains that the one percent materiality threshold leads to an appropriate level of risk being maintained by the DNSP (see chapter 16 - pass throughs).

M.4.4.4 Conclusion

The AER maintains its draft decision, that is, to reject the self insurance allowance for insurer credit risk event. This is because these costs will be recovered elsewhere through the regulatory regime - that is, through the pass through mechanism.

The AER notes SP AusNet's concerns regarding the one percent materiality threshold for this event. However, the AER considers that the costs incurred from this event would be substantial, and would likely meet the one percent materiality threshold. Further, because the event has not previously occurred, the cost of this risk cannot be substantiated but as discussed above the expected costs are likely to be minimal The AER will therefore treat this as a pass through event.

M.5 AER conclusion

The AER approves the following self insurance amounts for the Victorian DNSPs over the 2011-2015 regulatory control period:

Table M.6 AER's decision on CitiPower's self insurance allowance 2011–15 ($'m, 2010)

Risk	Revised regulatory proposal	AER determination
Liability	0	0
Motor vehicle	0.	0
Property	0	0
Total	**0**	**0**

Table M.7 AER's decision on Powercor's self insurance allowance 2011–15 ($'m, 2010)

Risk	Original regulatory proposal	AER determination
Liability	0	0
Motor vehicle	0	0
Property	0	0
Total	**0**	**0**

Table M.8 AER's decision on JEN's self insurance allowance 2011–15 ($'m, 2010)

Risk	Original regulatory proposal	AER determination
Substations—catastrophic or component failure	0	0
Other assets—storms and lightning	0	0
Other assets—pole fires	0	0
Damage to third party property	0..167	0.167
Public liability—fatality	0.051	0.051
Public liability—injury	0.304	0.304
Total	**2.669**	**0.522**[a]

(a) An allowance of $104 300 per year of the regulatory period

Table M.9 AER's decision on SP AusNet's self insurance allowance 2011–15 ($'m, 2010)

Risk	Revised regulatory proposal	AER determination
Liability—general	9.8	0
Poles and wires	8.9	6.5
Insurer default	0	0
Fraud	0	0
Total	**18.7**	**6.5**

Table M.10 AER's decision on United Energy's self insurance allowance 2011–15 ($'m, 2010)

Risk	Original regulatory proposal	AER determination
Liability —general	0.535	0
Liability—fire	0.245	0
Liability—asbestos	0.120	0.12
Poles and wires	2.710	0
Fraud	0.015	0
Insurer's default	0.125	0
Property	13.750	0
Contaminated land	2.380	0
Environmental	0.220	0
Total	**20.030**	**0.12**[a]

(a) An allowance of $24 000 per year of the regulatory period.

This appendix has assessed the proposed allowance for self insurance which is one component of each Victorian DNSP's proposed total forecast operating expenditure. The AER considers that the above amounts approved in this appendix are consistent with the requirement in clause 6.5.6(c) of the NER, that the total forecast operating expenditure reasonably reflects the operating expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast operating expenditure.

N Debt Raising Costs

Debt raising costs are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has accepted that debt raising costs are a legitimate expense for which a distribution network service provider (DNSP) should be provided an allowance.[1]

As noted at the beginning of the operating expenditure (opex) chapter, each Victorian distribution network service providers (Victorian DNSPs) proposed an allowance for debt raising costs as a component of their total proposed forecast operating expenditure for the 2011-15 regulatory control period. The assessment of debt raising costs is relevant to determining whether the AER is satisfied that the total proposed forecast opex or its estimate of the required opex reasonably reflects the opex criteria.

Specifically, this appendix assesses the proposed allowance and what the level of efficient expenditure for debt raising costs which a prudent operator, in the actual circumstances of each DNSP, would be required to incur based on a realistic expectation of the cost inputs required to achieve the opex objectives. This assessment in turn considers issues of direct debt raising costs and early refinancing costs as they relate to efficient and prudent costs of the opex criteria. As is discussed further in this appendix, the AER considers that the opex factors, particularly clause 6.5.6(e)(4), are relevant to this assessment.

The AER has assessed the benchmark debt raising costs of the Victorian DNSPs on this basis. Where consultant reports have been submitted by one of the Victorian DNSPs, to the extent that the information is pertinent to all Victorian DNSPs the information has been considered as applicable to all Victorian DNSPs within this appendix.

N.1 AER draft decision

The AER determined debt raising cost allowances for each of the Victorian DNSPs based on the refined Allen Consulting Group (ACG) benchmark debt raising cost method. The allowance for each firm was dependent on the number of benchmark sized debt issues required by each DNSP (based on the notional debt component of the RAB), and the nominal WACC applied to each DNSP. The allowance, expressed in basis points per annum (bppa), was applied to the benchmark debt portion of each DNSPs RAB (that is the benchmark 60 per cent gearing ratio applied to the DNSPs RAB) to determine the benchmark debt raising costs. These direct debt raising amounts (costs relating to: underwriting fees, legal fees, company credit rating fees and other transaction costs) excluded indirect debt raising costs (underpricing) and additional early refinancing costs (costs for raising debt at least 3 months prior to refinancing maturing debt). The draft decision debt raising cost allowance and applicable basis points are outlined in Table N.1.

[1] AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Final decision, 14 June 2007, pp. 94–97; AER, *SP AusNet transmission determination 2008–09 to 2013–14*, Final decision, 31 January 2008, pp. 148–150; AER, *ElectraNet transmission determination 2008–09 to 2013–14*, Final decision, 11 April 2008, pp. 84–85; AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, 28 April 2009, pp. 183–188, 541–560 (appendix N).

Table N.1 AER draft decision debt raising cost allowances

DNSP	Basis points per annum	$'m, 2010
CitiPower	9.3	3.79
Powercor	9.1	6.30
JEN	9.8	2.21
SP AusNet	9.1	5.96
United Energy	9.3	3.96

Source: AER, *Draft decision*, pp. 269–270.

N.2 Victorian DNSP revised regulatory proposals

Jemena electricity networks (JEN) and SP AusNet accepted the AER's draft decision on debt raising costs in their revised regulatory proposals. CitiPower, Powercor and United Energy did not accept the AER's draft decision on debt raising costs. The revised debt raising costs allowance proposed by the Victorian DNSPs are outlined in Table N.2.

Table N.2 Victorian DNSP revised proposed debt raising cost allowances ($'m, 2010)

DNSP	2011	2012	2013	2014	2015	Total
CitiPower	1.85	2.03	2.20	2.39	2.57	**11.04**
Powercor	3.19	3.48	3.77	4.04	4.32	**18.79**
JEN	0.44	0.48	0.53	0.56	0.59	**2.59**
SP AusNet	1.11	1.18	1.30	1.41	1.50	**6.50**
United Energy	0.75	0.82	0.88	0.93	0.95	**4.34**

Source: CitiPower, *Revised regulatory proposal*, p. 186; Powercor, *Revised regulatory proposal*, p. 175; JEN, *Post tax revenue model*; SP AusNet, *Revised regulatory proposal*, p. 264; United Energy, *Post tax revenue model*.

CitiPower and Powercor stated that they did not accept the AER's draft decision.[2] In particular they stated that they did not agree the early refinancing costs are included in the direct debt raising cost allowances determined by the AER. Both CitiPower and Powercor proposed allowances for early refinancing costs of 15.5 bppa in addition to the allocated direct debt raising costs allowances.[3] Both CitiPower and Powercor noted that this allowance should be updated by the AER in the final decision based on the agreed averaging period.

2 CitiPower, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 173; Powercor, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 175.

3 CitiPower, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 186; Powercor, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 175.

JEN accepted the draft decision and updated its opex forecasts in its revised regulatory proposal to reflect this.[4] JEN noted that its initial regulatory proposal was based on the New South Wales electricity distribution final decision and that the AER's draft decision used the same ACG method, which has been updated with minor refinements.

SP AusNet also accepted the AER's draft decision including the AER's position on early refinancing costs.[5] SP AusNet noted that its initial regulatory proposal was based on advice from the Competition Economists Group (CEG) and acknowledged the AER's draft decision's reasons for rejecting this proposal.

United Energy did not accept the AER's draft decision and noted that the allowance of 9.3 bppa was less than that proposed in its initial regulatory proposal.[6] United Energy further noted that its revised allowance on debt raising costs was contained in its post tax revenue model. The revised regulatory proposal also stated that United Energy intended to lodge a further submission on debt raising costs to support its claims.

N.3 Submissions

On 19 August 2010, in support of their revised regulatory proposals for early refinancing costs allowances CitiPower and Powercor provided a joint submission (CitiPower and Powercor submission) on the AER's draft decision for debt raising costs.[7]

This submission drew on a witness statement prepared by CitiPower's and Powercor's Chief Financial Officer (CFO's witness statement) which addressed early refinancing costs and contained confidential supporting information from third parties.[8]

On 7 October 2010 CitiPower and Powercor also provided an update to its submission (CitiPower and Powercor updated submission) to reflect updated proposals on debt raising costs based on their respective averaging periods.[9]

Although United Energy noted in its revised regulatory proposal that it intended to lodge a submission on debt raising costs, the AER notes a further submission was not provided.

4 Jemena electricity networks (JEN), *Revised regulatory proposal 2011–15*, 20 July 2010, p. 125.
5 SP AusNet, *Revised regulatory proposal 2011–15*, 20 July 2010, pp. 262–264.
6 United Energy, *Revised regulatory proposal 2011–15*, July 2010, p. 99.
7 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010.
8 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010.
9 CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs*, provided by email, 7 October 2010.

N.4 Issues and AER considerations

N.4.1 Direct debt raising costs

N.4.1.1 AER draft decision

The AER accepted that debt raising costs may be a legitimate expense for which a DNSP should be provided an allowance.[10] Debt raising costs are costs which are incurred each time debt is raised or refinanced. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs.

The AER used the ACG method to assess and determine the direct debt raising costs allowance for each of the Victorian DNSPs for the forthcoming regulatory control period.

N.4.1.2 Victorian DNSP revised regulatory proposals

As noted above, JEN and SP AusNet have accepted the AER's draft decision on debt raising costs while CitiPower, Powercor and United Energy revised regulatory proposals stated that overall they did not accept the AER's draft decision.

United Energy's revised regulatory proposal noted the direct debt raising cost allowance provided in the draft decision was less than its initial regulatory proposal.[11]

N.4.1.3 Submissions

The CitiPower and Powercor submission confirmed that both CitiPower and Powercor accepted the AER's draft decision on the amount of direct debt raising costs but did not accept that the costs of early debt refinancing is included in the allowance for direct debt raising costs.[12]

This submission also corrected for an inadvertent error regarding the direct debt raising costs allowance in CitiPower's revised regulatory proposal which noted that CitiPower accepted the 9.3 bppa allowance as per the AER's draft decision and not the 9.1 bppa as stated in its revised regulatory proposal.[13]

The 7 October CitiPower and Powercor updated submission confirmed these updated proposed allowances.[14]

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[10] AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Final decision, 14 June 2007, pp. 94–97; AER, *SP AusNet transmission determination 2008–09 to 2013–14*, Final decision, 31 January 2008, pp. 148–150; AER, *ElectraNet transmission determination 2008–09 to 2013–14*, Final decision, 11 April 2008, pp. 84–85; AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, 28 April 2009, pp. 183–188, 541–560 (appendix N).

[11] United Energy, *Revised regulatory proposal 2011–15*, p. 99.

[12] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 3.

[13] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 8.

[14] CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs"*, provided by email, 7 October 2010.

N.4.1.4 Issues and AER considerations

CitiPower, Powercor, JEN and SP AusNet have all accepted the AER's draft decision on direct debt raising costs.

United Energy proposed a higher allowance (in dollar terms) for debt raising costs than the allowance in the AER's draft decision. However, the AER notes that United Energy's post tax revenue model implements a unit rate of 9.3 bppa is the same unit rate as the AER's draft decision.[15] The difference between the AER's draft decision and United Energy's revised regulatory proposal is the higher RAB provided in United Energy's revised post tax revenue model. Therefore AER considers that United Energy's use of the 9.3 bppa is consistent with the AER's draft decision.

Having considered the Victorian DNSPs' revised proposals, the AER remains satisfied that the ACG method is an appropriate tool for assessing whether the proposed forecast direct debt raising costs allowances is consistent with the requirement that the total forecast expenditure reasonably reflects the opex criteria or for determining a forecast for direct debt raising costs that is consistent with that requirement.[16]

To ensure relevance to the context in consideration, ACG assessed actual debt issued by Australian utility and infrastructure companies, including domestic bonds, term loans and international bonds. The ACG method breaks down the direct debt raising costs into gross underwriting fees, legal and road show fees, company credit rating fees, issue credit rating fees, registry fees and paying fees.[17] A recommendation was made for the costs of each of these categories, based upon available evidence including Bloomberg and Standard and Poor's data. Since a proportion of these costs are fixed, the number of bonds issued in a regulatory control period has a material effect on debt raising costs. The ACG method determines the number of standard–size issues that are required to fund the debt portion of the opening RAB of each regulated firm, and apportions fixed and variable costs on this basis. This gives a benchmark percentage, which is applied to the debt portion of the RAB each year to determine the debt raising cost allowance.

The AER notes that the transaction cost inputs to the ACG method were recently updated to reflect current market values.[18] The AER notes that several features of the debt raising cost method provide the DNSPs with at least an efficient and prudent benchmark cost. Where ACG presented a range, the AER has been conservative and applied the upper boundary of this range. The AER also notes that in its use of the ACG method underwriting costs and median bond issue sizes are calculated using the Victorian DNSPs proposed averaging periods to reflect the most applicable prevailing market conditions.

The issues raised by Citipower and Powercor in relation to early refinancing costs are discussed in section N.4.2.4 below.

15 United Energy, *Post tax revenue model*, July 2010.

16 NER, clauses 6.5.6(c), 6.5.6(e)(4) and 6.12.1(4).

17 ACG, *Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission, Final report*, December 2004, p. 50.

18 AER, *South Australian distribution determination 2010–11 to 2014–15, Draft decision, Appendix I*, 25 November 2009, p. 527.

The AER has updated the rolling five year window for bond data used to determine the direct debt raising costs, based on the five year period ending on the averaging period, for the respective Victorian DNSPs. The AER considers that this is consistent with the AER's final decision overall.

As a result of this update, the underwriting costs are between 7.15 bppa and 7.32 bppa (depending on the respective Victorian DNSPs averaging period and WACC) and the benchmark sized debt issue remain at $250 million.

N.4.1.5 AER conclusion

Consistent with the AER's draft decision, and in accordance with the approach based on the ACG method, the AER has updated the benchmark direct debt raising costs allowance using the nominal WACC (used to amortise up-front costs) between 9.40 and 9.95 per cent. This results in the debt raising costs shown in Table N.3.

Table N.3 Final decision direct debt raising costs with a nominal WACC range between 9.40 and 9.95 per cent

Fee	Explanation	1 issue	2 issues	4 issues	6 issues	10 issues
Amount raised ($'m, nominal)	Multiples of median term notes ($250m)	250	500	1000	1500	2500
Gross underwriting fee	Median gross underwriting spread, upfront per issue	7.14–7.31	7.14–7.31	7.14–7.31	7.14–7.31	7.14–7.31
Legal and roadshow	$115k upfront per issue	0.73–0.75	0.73–0.75	0.73–0.75	0.73–0.75	0.73–0.75
Company credit rating	$50k per annum	2.00	1.00	0.50	0.33	0.20
Issue credit rating	4 basis point up front per issue	0.63–0.65	0.63–0.65	0.63–0.65	0.63–0.65	0.63–0.65
Registry fees	$3.5k up front per issue	0.14	0.14	0.14	0.14	0.14
Paying fees	$4/$1 million per annum	0.04	0.04	0.04	0.04	0.04
Total	**Basis points per annum**	**10.7–10.9**	**9.7–9.9**	**9.2–9.4**	**9.0–9.2**	**8.9–9.1**

Source: AER analysis.
Note: The ranges reflect the DNSPs different averaging periods and nominal WACC.

N.4.2 Early refinancing costs

N.4.2.1 AER draft decision

The AER considered that it is prudent for the benchmark efficient firm to manage refinancing risk and that the DNSPs should be compensated for the efficient and prudent costs of a refinancing plan. However, the draft decision did not consider that the additional early refinancing costs allowance proposed by CitiPower, Powercor and SP AusNet should be added to the direct debt raising costs allowance. From a theoretical perspective, the AER considered that there will be a point where the marginal cost to further reduce refinancing risk outweighs the marginal benefit to do so. In this respect the AER noted it will only allow the efficient and prudent costs required for the benchmark firm to refinance its debt.

In addressing claims for further reducing risk, the AER evaluated the three competing methods for early debt refinancing (completion, commitment and underwriting methods) as stated by Standard and Poor's.[19] The AER's analysis demonstrated that the underwriting method (based on underwriting volume only) was the efficient and prudent option.

Further, the AER considered that the description of the underwriting volume only approach to early refinancing and the description of the underwriting component in the ACG method were similar. As the costs of both approaches were comparable, the AER considered that to include an underwriting allowance for early refinancing costs in addition to the ACG underwriting component would be double counting.

Therefore, based on the ACG method, the AER's draft decision considered that the allowance for direct debt raising costs already included the efficient costs of a refinancing plan and that no additional allowance for early refinancing costs was required.

N.4.2.2 Victorian DNSP revised regulatory proposals

SP AusNet accepted the AER's draft decision on refinancing plans.[20] However, CitiPower and Powercor did not accept the AER's draft decision and stated that early refinancing costs were not included in the direct debt raising costs allowance as determined by the ACG method.[21]

CitiPower and Powercor proposed an allowance of 15.5 bppa for early refinancing costs in addition to the allowance for direct debt raising costs for the forthcoming regulatory control period.[22]

N.4.2.3 Submissions

The CitiPower and Powercor submission stated that a prudent DNSP, in minimising its refinancing risk, would take dedicated measures at least three months in advance of maturing debt to ensure that it had the appropriate funds on the date its existing debt matured.[23] The submission stated that the underwriting component in the ACG method, considered and costed in the AER's draft decision, was not an appropriate means to eliminate this refinancing risk as it is a 'book build' component which covers

19 Standard and Poor's, *Ratings direct: Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam*, 22 April 2008.

20 SP AusNet, *Revised regulatory proposal 2011–15*, p. 264.

21 CitiPower, *Revised regulatory proposal 2011–15*, p. 186, Powercor, *Revised regulatory proposal 2011–15*, p. 175.

22 CitiPower, *Revised regulatory proposal 2011–15*, p. 186, Powercor, *Revised regulatory proposal 2011–15*, p. 175.

23 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 3.

the establishment fee of the bond issue, typically covers a period of 3 to 7 days and does not reduce a firm's refinancing risk.[24]

On this basis, the CitiPower and Powercor submission considered:

> …that the AER's conclusions are incorrect and a separate allowance for early refinancing costs is required in addition to the standard allowance for direct debt raising costs.[25]

In determining what it considered is the appropriate approach that a prudent operator would undertake to reduce refinancing risk, the CitiPower and Powercor submission drew on the CFO's witness statement which excluded the underwriting method as inappropriate and examined the merits of the completion method, the commitment method, the use of cash reserves and the use of a committed bank loan facility.[26]

The CitiPower and Powercor submission stated that:

- Of the three methods considered in the AER's draft decision the completion method remained the efficient method.
- There is evidence that 'comparable gas and electricity operators' utilise the completion method.
- Of the alternative potential methods considered in the submission, the committed bank loan facility provided the least cost option and the CFO's witness statement further considered that it was the least cost option, even in comparison to the completion method. However, the CitiPower and Powercor submission noted that there were additional time and indirect costs not factored into the estimate it considered.[27]

Based on the CFO's witness statement, the CitiPower and Powercor submission proposed that an additional allowance is required for early refinancing costs which are equal to the average of the completion method with no buyback provisions and a committed bank loan facility.[28]

The CitiPower and Powercor updated submission, based on their respective averaging periods, recalculated the early refinancing costs as an allowance of 15.2 bppa.[29]

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24 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, pp. 6–7.

25 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 7.

26 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 2.

27 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 3.

28 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 3.

29 CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs"*, provided by email, 7 October 2010.

N.4.2.4 Issues and AER considerations

The AER maintains that DNSPs should be compensated for the efficient and prudent costs of a refinancing plan. However, consistent with its draft decision and based on its analysis and considerations of issues set out below, the AER considers:

- DNSPs should only be allowed the efficient and prudent costs required for a refinancing plan which may include early refinancing activities
- in establishing the efficient and prudent debt raising cost allowances for network service providers the AER is informed by the analysis in the ACG method
- the ACG report (which set out the ACG method) was a comprehensive investigation into debt raising costs and incorporates refinancing elements
- in assessing early refinancing costs, the AER's analysis included the Standard and Poor's approaches (completion, commitment and underwriting methods) as well as two alternative approaches (cash reserves and a committed bank loan facility) submitted by CitiPower and Powercor
- based on this analysis the underwriting volume only method remains the efficient and prudent approach
- the characteristics and costs of the underwriting volume only method are consistent with the underwriting component in the ACG method and therefore to include this additional allowance would be inefficient.

Therefore, the AER does not consider that the allowance proposed by CitiPower and Powercor associated with early refinancing costs should be added to the direct debt raising costs allowances. The AER considers that to do so would be double counting the costs of managing refinancing risk. The AER considers that based on the ACG method the benchmark debt raising costs allowance already includes the efficient and prudent costs of a refinancing plan including early refinancing costs through underwriting volume only and that no increase in these costs is required. This is discussed further below.

The AER notes that the arguments put forward in the CitiPower and Powercor submission and the CFO's witness statement are an extension of the arguments put forward by ETSA Utilities and its consultant Pricewaterhouse Coopers (PwC) for the AER's 2010–15 South Australia distribution determination. The AER notes that its draft decision reflects its position in the final decision for 2010–15 South Australia distribution determination as the information provided by stakeholders for the South Australian final decision was in greater detail and further progressed than the information provided by the Victorian DNSPs on this issue in their initial regulatory proposals.

The following sections examines the CitiPower and Powercor submission (including the CFO's witness statement) in the context of the AER's previous considerations in both the draft decision and the final decision for the South Australian distribution determination on refinancing plans, specifically in regard to:

- framework for assessment
- validity of a refinancing plan
- comparable actions of gas and electricity businesses and the efficient and prudent costs of debt refinancing
- assessment of early refinancing methods, including
  - underwriting method
  - completion method
  - commitment method
  - alternative methods.

Framework for assessment

The AER noted in the draft decision that the evaluation of early refinancing costs should take into account the benchmark expenditure that would be incurred by an efficient and prudent DNSP. Consistent with recent AER decisions on debt raising costs and the AER's Statement of Regulatory Intent (SORI), the AER considers the benchmark efficient firm maintains a 60 per cent gearing ratio and issues debt with a ten year term at a BBB+ credit rating.[30]

For analytical purposes, the benchmark efficient firm is a theoretical concept, and the AER acknowledges that it is unlikely that a real world firm will exactly match the benchmark. For the purposes of establishing benchmark debt raising costs allowances, the AER establishes a data set under the ACG method, comprised of businesses that closely resemble the theoretical benchmark–that is, the benchmark is informed by the observed actions of these businesses.

The AER notes that the benchmark opex that would be incurred by an efficient DNSP is one of the relevant factors of the NER that the AER must have regard for in determining that a DNSPs total forecast opex reasonably reflects the opex criteria.[31] In considering the benchmark debt raising costs that would be incurred by an efficient and prudent DNSP the AER is informed by the analysis in the ACG method. The AER also notes that the NEL requires that a DNSP should be provided with a reasonable opportunity to recover at least its efficient costs.[32]

Therefore where the AER has provided an allowance on this basis, a particular DNSP is not bound to follow the efficient and prudent approach as approved or determined by the AER under the NER but rather is free to adopt an alternative approach, accepting the benefits or detriments that arise as a consequence of deviation from this efficient and prudent approach.

30 AER, *Victorian draft decision*, pp. XXXIX–XLII, 484–485, 506; AER, *South Australian distribution determination 2010–11 to 2014–15, Final Decision*, May 2010, pp. 171–172, 193; AER, *Queensland distribution determination 2010–11 to 2014–15, Final Decision*, May 2010, pp. 238–239, 267.; AER, SORI, May 2009, pp. 79–82, 101–110.

31 NER, clauses 6.5.6(e)(4) and 6.5.6(c).

32 NEL, clause 7A(2).

The ACG benchmark debt raising costs method has been applied by the AER consistently across jurisdictions and across both gas and electricity businesses. While the AER has made some refinements to the ACG method the components have not been altered. The AER considers that it remains an appropriate tool for assessing whether the proposed forecast direct debt raising costs allowances are consistent with the requirement that the total forecast expenditure reasonably reflects the opex criteria or for determining a forecast for debt raising costs that is consistent with that requirement.[33]

The AER has assessed the proposals from CitiPower and Powercor for early refinancing costs including the alternative and competing methods for establishing early refinancing costs on this basis which is set out below. The AER's analysis informs its considerations whether the proposals are consistent with the requirement that the total forecast reasonably reflects the opex criteria.[34]

Validity of a refinancing plan

The AER's draft decision considered that it is prudent for the benchmark firm to manage refinancing risk. The benchmark firm maintains an investment grade credit rating (BBB+) and therefore should meet the requirement of credit rating agencies such as Standard and Poor's for a firm of this credit rating. The AER agrees with the CFO's witness statement that the refinancing plan is to ensure that a firm remains a going concern and reduce the risks of insolvency.[35]

The AER's draft decision considered that the benchmark firm will manage its refinancing risk through a refinancing plan and noted:

- the refinancing plan will set out a timeline for actions by the firm to ensure that it does not default on its debt
- may include the use of the completion, commitment or underwriting methods but is not limited to these and will encompass a broader range of actions by the firm
- the refinancing plan also includes management of maturity dates, cash reserves and other credit facilities (such as working capital account) to reduce refinancing risk.[36]

Reiterating its draft decision, the AER notes that managing refinancing risk is not new and has been a long term fundamental requirement for a benchmark firm. The AER notes that this is supported by Standard and Poor's, where it noted:

> Liquidity and liability management have always been key components of our rating methodology and their importance within credit analysis have been borne out in the current credit market conditions.[37]

[33] NER, clauses 6.5.6(c), 6.5.6(e)(4) and 6.12.1(4).
[34] NER, clauses 6.5.6(c).
[35] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 3.
[36] AER, *Draft decision, Appendix P*, p. 341.
[37] Standard and Poor's, *Ratings Direct: Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam*, 22 April 2008, p. 6.

The CFO's witness statement made a similar comment:

> The need to manage liquidity risk is not new, but has been given increased importance and attention since the global financial crisis where many firms encountered severe difficulties in refinancing debt.[38]

Similar statements were made in the context of the AER's South Australian final decision where PwC noted:

> Although the mitigation of refinancing risk has been heightened by the Global Financial Crisis, refinancing risk has always been a major focus for borrowers.[39]

Likewise Handley noted:

> Whilst recent events in world credit markets have arguably drawn more attention to the issue of refinancing risk, in my view, the prudence of an appropriate financing plan was well accepted before then and will continue to remain thereafter.[40]

The AER notes that Standard and Poor's comments were concerned with the 2008 financial market conditions.[41] The AER noted in the South Australian final decision that statements from Australian and international economic authorities support the conclusion that the financial market conditions that characterised the GFC are likely to abate over the forthcoming regulatory control period.[42]

The AER considers that there is evidence that investor confidence in the debt market has increased recently with the Australian Pipeline Trust issuing BBB rated bonds with a 10 year tenor in July this year. A bond of this credit rating and this tenor is an encouraging sign that market conditions have improved since 2008 and the AER considers that this is consistent with its view in the South Australian final decision.

With financial market conditions now less volatile and dysfunctional than during the GFC and, as stated above, acknowledging that managing refinancing risk is not new and has been a long term fundamental requirement for a benchmark firm, the AER remains of the opinion that there is unlikely to be qualitative difference between the refinancing plans required by the benchmark firm in earlier regulatory control periods and the current need for a refinancing plan.

Comparable actions of gas and electricity businesses and the efficient and prudent costs of debt refinancing

The CitiPower and Powercor submission claimed that the summary of actions presented in table 1 of the CFO's witness statement demonstrates that other comparable gas and electricity businesses refinance their debt anywhere from

38 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 5.

39 PwC, *ETSA Utilities: Distribution network service provider refinancing costs, Final report*, February 2010, p. 23.

40 Handley, *Note on the completion method*, April 2010, pp. 7–8 (and footnote 11).

41 Standard and Poor's, *Ratings Direct: Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam*, 22 April 2008, pp. 2–7.

42 RBA, *Minutes of the monetary policy meeting of the reserve bank board*, 2 March 2010.

3 months to over a year prior to maturity.[43] Based on this, the CitiPower and Powercor submission claimed that their proposed allowance for early refinancing costs reflects prudent actions of a DNSP in their circumstances and therefore the costs reasonably reflects clause 6.5.6(c) of the NER and should be included in their respective opex forecasts.

The AER notes that table 1 of the CFO's witness statement is an extension of the table provided by PwC in its expert opinion report for the South Australian final decision.[44]

The AER has previously acknowledged that the set of comparator firms that inform the benchmark do use refinancing plans, including, observed use of the completion method. However, the AER notes that while network service providers can adopt different refinancing arrangements, the allowance determined by the AER under the NER requires that only the efficient and prudent costs of a refinancing plan should be provided.

The analysis in the AER's draft decision demonstrated that the efficient and prudent costs were based on the underwriting volume only method. The ACG method already includes an underwriting component which is comparable to the underwriting volume only method and therefore to include an additional allowance would be double counting these costs.

The AER determines the compensation for raising debt in terms of efficient and prudent costs and a realistic expectation of the cost inputs.[45] The AER does this with regard to the benchmark expenditure that would be incurred by an efficient DNSP.[46] The AER considers the ACG method is an appropriate tool for determining this expenditure. The circumstances of the DNSP are also taken into account by applying the benchmark efficient costs in proportion to the DNSPs notional debt component of its RAB. The benchmark approach is also consistent with NEL revenue and pricing principles by providing the DNSPs with a reasonable opportunity to recover at least the efficient costs.[47] Therefore a DNSP is not bound to follow the approach which is consistent with the AER's assessment of efficient and prudent, and is free to adopt an alternative approach, accepting the benefits or detriments that arise as a consequence of doing so.

As stated above, in establishing the efficient and prudent debt raising cost allowances for network service providers the AER is informed by the analysis in the ACG method. The ACG method utilises observed actions of businesses that closely resemble the theoretical benchmark including some of those businesses provided in table 1 of the CFO's witness statement. However, not all of the observations in table 1 of the CFO's witness statement have been included as they do not closely resemble the theoretical benchmark. For example, the ACG method utilises observations in the domestic medium term note market to determine the median sized bond issue component. The AER notes that many of the observations in table 1 of the CFO's

43 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 6.

44 PwC, *ETSA Utilities: Distribution network service provider refinancing costs, Final report*, February 2010, p. 23.

45 NER, 6.5.6(c).

46 NER, 6.5.6(e)(4).

47 NEL, clause 7A(2).

witness statement were issued in international markets and therefore have not been included.

The AER notes that the domestic medium term note market is a good proxy for establishing the efficient and prudent debt raising costs for network service providers as this is consistent the assumptions for the cost of debt which is based on Australian debt markets. As stated above, these inputs are updated consistent with a DNSP's agreed averaging period to appropriately reflect the most applicable prevailing market conditions.

The AER notes that table 1 of the CFO's witness statement demonstrates that comparable gas and electricity businesses undertake early debt refinancing. However, under the NER, the AER's role is approve or determine the efficient and prudent costs relating to debt refinancing.[48] Based on this, the AER's draft decision determined that no additional allowances were required for a refinancing plan as the allowance based on the ACG method already included the efficient and prudent costs.

Consistent with the AER's draft decision, the AER's evaluation of the benchmark approaches to early debt refinancing to determine the method that is efficient and prudent is discussed below.

Assessment of early refinancing methods

The AER reiterates that consistent with its previous application of the ACG method, the AER considers that the ACG analysis was a comprehensive review of the transaction costs involved in raising debt (and equity) which the AER considers included the management of refinancing risk.[49] As noted above, the AER acknowledges that businesses can deviate from the approach which is consistent with the AER's assessment of efficient and prudent costs and undertake a range of options to reduce their refinancing risk accepting the benefits or detriments that arise as a consequence of their actions. In determining the direct debt raising costs allowances the AER has regard to the benchmark expenditure that would be incurred by an efficient DNSP to manage refinancing risk.

Consistent with the AER's draft decision, an evaluation of the efficient and prudent approaches to refinancing risk as presented in the CFO's witness statement is provided below. This evaluation demonstrates that the underwriting volume only approach is the efficient and prudent approach. Based on this an additional benchmark allowance for early refinancing costs, added to the direct debt raising costs allowance, would be double counting the costs of managing refinancing risk and therefore not efficient.

The alternative and competing methods proposed by the CFO's witness consist of:

- underwriting method
- completion method
- commitment method

48 NER, clauses 6.5.6(c).

49 ACG, *Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission, Final report*, December 2004, pp. 2–7.

- cash reserves
- committed bank loan facility

Underwriting Method

The underwriting method is achieved by engaging a third party to underwrite the transaction, three months prior to the refinancing date.

The AER notes that the CitiPower and Powercor submission claimed that the underwriting method is not a prudent option to manage refinancing risk due to its high level of risk and therefore have not modelled or provided estimates for this approach.[50] This is further discussed in the CFO's witness statement.[51] However the AER notes that in several instances commentators (including CitiPower and Powercor) have endorsed the availability and use of the underwriting method as a prudent approach. This is discussed below.

In support of its claims for early refinancing costs for the South Australian final decision, the AER notes that ETSA Utilities based its claims on an article by Standard and Poor's who noted:

> It's not possible to generalize, but if the refinancing of a significant impending debt maturity had not been completed, committed, or **underwritten** three months prior to the maturity date, then a rating action would be likely.[52]

CitiPower and Powercor also drew reference to this Standard and Poor's article in their respective initial regulatory proposals and further noted that the Treasury Risk Management Policy of CHEDHA Group (the holding company for CitiPower and Powercor investments):[53]

> …requires that debt funding requirements are committed, **underwritten** or full funded at least six months prior to the requirement for funding.[54]

[text removed – commercial–in–confidence]

Similarly, the AER notes that ETSA Utilities engaged Pricewaterhouse Coopers (PwC) as an expert to cost the underwriting approach as one of the three competing

50 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 6.

51 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 16.

52 Standard and Poor's, *Ratings Direct: Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam*, 22 April 2008, p. 7. Emphasis added.

53 Cheung Kong Infrastructure Ltd and Hong Kong Electric Holdings Ltd Electricity Distribution Holdings (Australia) Pty Ltd.

54 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 5; CitiPower, *Regulatory proposal 2011–15*, p. 173, Powercor, *Regulatory proposal 2011–15*, p. 170. Emphasis added.

prudent approaches to early refinancing for the South Australian final decision.[55] The AER notes that PwC's analysis confirmed a cost for the underwriting method and that the AER's draft decision drew on PwC's analysis in determining the appropriateness of an allowance for early refinancing costs. The AER considers that PwC's analysis as an expert is widely regarded and this is supported in the CitiPower and Powercor submission where they quote PwC to support its arguments against the underwriting method.[56]

Based on this, the AER maintains its position that the underwriting method is one of the competing approaches to early refinancing.

The AER notes that the underwriting option considered appropriate in its draft decision was to underwrite volume only, rather than the volume and the price. This option was one of a range of options for the underwriting method proposed by PwC as an expert opinion.[57] The AER's draft decision considered that this approach was appropriate for the benchmark firm as it enabled a firm to enter into an underwriting contract without locking in a price and then sell at the prevailing price during the averaging period. This approach was considered a lower risk and cost than the approach of underwriting both volume and price.

The CFO's witness statement considered that the underwriting component of the ACG method is not a method of managing refinancing risk, and therefore in managing refinancing risk an additional allowance is required to cover these costs.[58]

Consistent with its draft decision, the AER considers that the ACG method used for assessing debt raising costs does take account of the management of refinancing risk.

The AER notes:

- there are strong grounds to consider that debt raising costs already includes sufficient provision for managing refinancing risk considering:
  - the 2004 ACG report was a comprehensive review of the transaction costs involved in raising debt (and equity)
  - the issue of refinancing risk was known and relevant when ACG undertook its analysis
  - the AER considers that it is reasonable to conclude that ACG took into account the need for a refinancing plan to mitigate refinancing risk (to an appropriate level) when estimating a benchmark for debt raising costs

55 PwC, *ETSA Utilities: Distribution network service provider refinancing costs, Final report*, February 2010, p. 19-21.
56 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 7.
57 PwC, *ETSA Utilities: Distribution network service provider refinancing costs, Final report*, February 2010, p. 19-21.
58 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 14-16.

- the refined ACG method still uses the same components as recommended in the 2004 ACG method which explicitly includes an underwriting component, currently estimated at between 7.14 and 7.31 basis points per annum.

As noted above, Standard and Poor's, PwC, Handley and the CFO's witness statement acknowledged that managing refinancing risk is not new. ACG also noted in its conclusions of its analysis of domestic corporate banking and bond markets:

> Our analysis of debt characteristics and issuance fees charged for different types of debt shows a wide variability if fees (bppa) based primarily on risk and tenor.[59]

Therefore, the AER considers that it is reasonable to conclude that ACG took into account the need for a refinancing plan to mitigate refinancing risk (to an appropriate level) when estimating the appropriate benchmark allowance for debt raising costs.

The AER notes that the mitigation of refinancing risk is included in the underwriting fee, which is supported by ACG where it noted:

> Traditionally, as in stockbroking, the underwriting fee represented a reward for risk taking. If the issue were not sold, the underwriter would take it up and guarantee proceeds to the issuer.[60]

That is, the underwriting fee represents the reward for the risk assumed by the underwriter for the debt issuance. Therefore, one would expect to see debt issuance with a higher risk incur a higher underwriting fee than debt issuance with a lower risk. The ACG method has regard to this by calculating gross underwriting fees by applying a five–year rolling average to represent the long-term costs and avoid short term fluctuations in market conditions.

The AER reiterates that the ACG report was a comprehensive review of the transaction costs involved in raising debt (and equity).[61] The brief for ACG was not constrained and asked for inclusion of all aspects of the debt raising process for a benchmark firm.

The AER also notes that the underwriting description from the ACG report matches that in the PwC report. The AER notes that the CFO's witness statement definition of underwriting is also consistent with these, which noted:

> I define the underwriting method as the engagement of a third party under a documented and executed agreement to underwrite the refinancing transaction at least three months prior to the refinancing date (Underwriting Method). If the debt is not purchased by investors on the date of issue, then the underwriter will be required to purchase all of the debt. This definition is

59 ACG, *Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission, Final report*, December 2004, p. 44.

60 ACG, *Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission, Final report*, December 2004, p. 38.

61 ACG, *Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission, Final report*, December 2004, pp. 2–7.

consistent with the definitions adopted in the Draft Determination and in the PwC Report.[62]

The AER also notes that the, PwC report included a 'volume only' underwriting method, where the underwriter did not guarantee the price at which the debt would be raised.[63] ACG explicitly noted this type of underwriting, although it used a different label:

With "best efforts" underwriting, a "bookbuild" is undertaken to determine the market–clearing price.[64]

Based on the discussion above, the AER does not accept the CFO's witness statement that the ACG method, particularly the underwriting component, does not provide compensation for the management of refinancing risk. Further, as per the definitions of the underwriting method above and the analysis set out below, the AER considers that an additional allowance for underwriting costs above that provided in the ACG method would lead to some double counting.

The AER therefore maintains its view that the underwriting method is an appropriate method for early refinancing. Further, the AER considers that the volume only underwriting method is appropriate as it considers it is lower in risk and cost than the approach of underwriting both volume and price. Based on this the AER has updated its underwriting method costs to reflect current market data and accommodating the time value of money which are reported in Table N.4.

Table N.4 Cost of underwriting method

Item	AER draft decision		AER final decision	
Scenario	**Low**	**High**	**Low**	**High**
Up–front cost (basis points)	25	50	25	50
Discount rate (%)	9.68	9.68	9.40	9.40
Converted up-front cost (bppa)	4	8	4.0	7.9
Total unit rate (bppa)	**4**	**8**	**4.0**	**7.9**

Source: AER analysis.

The AER considers that the underwriting cost estimate based on the ACG method (7.14–7.31 bppa) falls within the AER's estimated costs range based on the volume only analysis (4.0 to 7.9 bppa), albeit at the upper end of this range. Consistent with the AER's draft decision and the analysis above, the AER considers that the description of the underwriting volume only approach to early refinancing and the description of the underwriting component in the ACG method are similar. As the costs and descriptions of underwriting are comparable, the AER considers this

62 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 10.

63 PwC, *ETSA Utilities: Distribution network service provider refinancing costs, Final report*, February 2010, p. 19.

64 ACG, *Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission, Final report*, December 2004, p. 38.

provides further weight to the consideration that the ACG method used for assessing debt raising costs already includes the efficient costs for the management of refinancing risk.

Completion Method

The completion method is achieved by executing the refinancing transaction three or more months prior to the date it is required.

The AER notes that the CitiPower and Powercor submission claimed that of the alternative approaches in the AER's draft decision the completion method is the efficient option that a prudent firm would undertake in reducing refinancing risk.[65] This is further noted in the CFO's witness statement.[66]

As stated above, both the CitiPower and Powercor submission and the CFO's witness statement noted that there is evidence that comparable electricity and gas businesses refinance their debt utilising the completion method anywhere from 3 months to over a year prior to maturity.[67] The CFO's witness statement claims that due to this evidence and the CFO's witness statement modelling, the completion method is the appropriate efficient approach to managing refinancing risk.[68]

The AER acknowledges that businesses undertake early refinancing activity. However, the AER notes that it establishes an allowance based on the costs that are consistent with the requirement that total forecast opex reasonably reflect the opex criteria. In establishing these allowances the AER has regard to the benchmark opex that would be incurred by the efficient DNSP. DNSP's are free to adopt an alternative approach, accepting the benefits or detriments that arise as a consequence of deviation from the efficient and prudent approach.[69]

With respect to the CFO's witness statement modelling of the completion method, the AER notes that the option to invest in Treasury bonds has been excluded.[70] The CFO's witness statement claimed that this is because the lower risk approach of investing in Treasury bonds results in a higher cost when compared to investing all funds in bank bills or investing in a portion of bank bills and using the remaining funds to buy back existing bonds. Therefore only the two later options are modelled in the CFO's witness statement. Further the AER notes that the CitiPower and Powercor submission further narrowed this scope as it only considered the approach of investing all funds in bank bills with no buy back provisions.[71]

65 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 3.

66 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 19–20.

67 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 6; CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 6–10.

68 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 24.

69 NEL, clause 7A(2), NER, clause 6.5.6(c).

70 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 19–20.

71 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, pp. 2–8.

Consistent with its draft decision, the AER has calculated the completion method in bank bills as well as an early redemption of bonds with a take up rate between zero and one hundred per cent. These calculations are modelled on early refinancing 3 months prior to maturity.

The AER has updated the CFO's witness statements calculations for the costs of the completion method to reflect the data provided in the CitiPower and Powercor updated submission. The AER has also calculated the completion method updated to reflect the AER's final decision on the nominal WACC to be applied to CitiPower and Powercor. Table N.5 present the AER's calculation of commitment method costs, including updated market data.

Table N.5 Cost of the completion method

Item	**CitiPower & Powercor updated submission**	**AER final decision**
Risk–free rate (10 year CGS) (%)	5.08	5.08
Debt risk premium	4.13	3.74
Interest rate on funds borrowed (%)	9.21	8.82
BBSW (%)	4.74	4.74
BBB+ margin above BBSW (%)	0.5	0.5
Interest rate on funds lent (%)	5.24–4.74	5.24–4.74
Difference in interest rates	3.97–4.47	3.58–4.08
Up–front cost (basis points)	99.3–111.8	89.5–102.0
Discount rate (%)	9.64	9.40
Unit rate (bppa)	**15.9–17.9**	**14.2–16.2**

Source: CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 19–20; CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs"*, provided by email, 7 October 2010; AER analysis.

After adjusting for current market data and accommodating the time value of money, the AER considers that the costs of the completion method are in the range of 14.2 to 16.2 bppa. As noted above, the AER allows or determines the efficient and prudent costs required by a DNSP to manage refinancing risk. In comparison to its analysis of the underwriting volume only approach above, the AER considers that the completion method is not an efficient approach and is not consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast opex reasonably reflects the opex criteria.

Commitment Method

The commitment method is achieved by signing contracts to commit parties to the refinancing three or more months prior to the date of the actual funds transfer.

The AER notes that the CitiPower and Powercor submission, including the CFO witness statement, noted that the commitment method is one of the 'potential' alternative approaches that a prudent firm would undertake in reducing refinancing risk.[72] The CFO's witness statement also provided an estimate of its cost.[73] However, the AER notes that the CitiPower and Powercor submission did not propose this as an approach that CitiPower or Powercor would undertake.

Further, the CFO's witness statement disagreed with the AER's draft decision and the South Australian final decision that investors do not require compensation for opportunity costs where the bond buyer wants to purchase a bond in three months time and want certainty in advance that such a purchase can be made. This differs from the opportunity cost of the investor who prefers to buy a bond immediately and therefore wants compensation for the delay between the commitment and execution.

In support of its claim, the CFO's witness statement referred to its table 1 and noted that:

> If investors did not require compensation for opportunity costs then this method would be significantly cheaper than the Completion Method and market evidence should show that most comparable firms use the Commitment Method in practice.[74]

Consistent with its draft decision on agent preferences, the AER acknowledges that estimation of opportunity costs inevitably involves assumptions. The AER acknowledges the CFO's witness statement that investors have alternatives in their choices to invest which includes taking into consideration forward curve pricing.[75] However, the AER considers that to generalise that all investors would take a particular action is an unreasonable assumption. Therefore, consistent with its draft decision the AER has modelled the maximum possible range of opportunity cost for the commitment method between where all investors either require no compensation to where all investors require compensation (that is, between zero and one hundred per cent). The AER has updated the CFO's witness statements calculations for the cost of the commitment method to reflect the data provided in the CitiPower and Powercor updated submission. The AER has also calculated the use of cost of the commitment method updated to reflect the AER's final decision. Table N.6 present the AER's calculation of commitment method costs, including updated market data.

72 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 2.

73 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 20–21, 23–24.

74 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 21.

75 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 20–21.

Table N.6 Cost of the commitment method

Item	CitiPower & Powercor updated submission	AER final decision
Cost of the completion method (bppa)	17.9	14.2–16.2
Opportunity cost (as a proportion of completion method costs)	100%	0–100%
Unit rate (bppa)	**17.9**	**0–16.2**

Source: CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 21; CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs"*, provided by email, 7 October 2010; AER analysis.

After adjusting for current market data, accommodating the time value of money, and allowing for variation in the opportunity cost, the AER considers that the costs of the commitment method are in the range of 0 to 16.2 bppa. As noted above, the AER allows or determines the efficient and prudent costs required by a DNSP to manage refinancing risk. While the AER notes that its analysis demonstrates that the commitment method could potentially be the least cost option as it has a cost range that extends down to 0 bppa (where no investors require compensation), there is considerable uncertainty in the cost estimate for this method which extends up to 16.2 bppa (where all investors require compensation). Therefore having regard to its analysis of the underwriting volume only approach above, the AER considers that on balance the commitment method is not an efficient approach and is not consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast opex reasonably reflects the opex criteria.

Alternative Potential Methods

The CitiPower and Powercor submission proposed two additional alternative potential methods that a prudent firm would undertake in reducing refinancing risk.[76] These approaches are:

- Use of cash reserves
- A committed bank loan facility.

The CFO's witness statement also proposed these as alternative approaches and modelled the costs of utilising such approaches.[77]

Use of cash reserves

[76] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 2.

[77] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 21–23.

With respect to the use of cash reserves approach, the AER notes that again the CitiPower and Powercor submission did not propose this as an approach that CitiPower or Powercor would undertake. Further, the AER notes that the CFO's witness statement considered that this was the most expensive approach it modelled (21.6 bppa) and therefore it would be unlikely that this method would be undertaken by a prudent firm in managing its refinancing risk.[78] The AER has updated the CFO's witness statements calculations of the cash reserves to reflect the data provided in the CitiPower and Powercor updated submission. The AER has also calculated the use of cash reserves updated to reflect the AER's final decision on the nominal WACC to be applied to CitiPower and Powercor. Table N.7 presents these revised calculations.

Table N.7 Cost of the use of cash reserves

Item	CitiPower & Powercor updated submission	AER final decision
Nominal WACC (%)	9.64	9.40
BBSW (%)	4.74	4.74
Difference in interest rates	4.90	4.66
Up–front cost (basis points)	122.6	116.6
Discount rate (%)	9.64	9.40
Unit rate (bppa)	**19.6**	**18.5**

Source: CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 21, CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs"*, provided by email, 7 October 2010; AER analysis.

After adjusting for the CitiPower's and Powercor's nominal WACC, the AER considers that the costs of the use of cash reserves are 18.5 bppa. As noted above, the AER allows or determines the efficient and prudent costs required by a DNSP to manage refinancing risk. In comparison to its analysis of the underwriting volume only approach above, the AER considers that the use of cash reserves is not an efficient approach and is not consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast opex reasonably reflects the opex criteria.

Committed bank loan facility

With respect to the committed bank loan facility, the CitiPower and Powercor submission noted that this would be established specifically with the intention to manage refinancing risk regarding a maturing debt.[79] The CitiPower and Powercor submission noted that of the options modelled this was the least cost option (12.5 bppa) however additional time, resources and indirect costs were not included in this estimate. It further noted that it was unlikely that this method by itself would be

[78] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 21–22.

[79] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 3.

undertaken by a prudent firm in managing refinancing risk. Based on this, the CitiPower and Powercor submission noted that in addition to the allowance for direct debt raising costs a further allowance should be included for early refinancing costs which would be equal to the average of the completion method with no buy back facilities and a committed bank loan facility (15.5 bppa).

The modelling of approaches in the CFO's witness statement demonstrated that the committed bank loan facility was the least cost option and noted that this option would include additional legal, internal and bank expenses and resources which would be required each time debt is refinanced making this option less efficient. It also noted that this method would also put strains on a firm's relationship with its banks.[80] Based on the totality of this method, the CFO's witness statement notes:

> Accordingly, I consider that a prudent firm is unlikely to adopt the Committed Bank Loan Facility as its sole method of managing refinancing risk.[81]

The AER has updated the CFO's witness statements calculations for the committed bank loan facility to reflect the data provided in the CitiPower and Powercor updated submission. The AER has also calculated the committed bank loan facility updated to reflect the AER's final decision on the nominal WACC to be applied to CitiPower and Powercor. Further, where the CitiPower and Powercor updated submission has used an average establishment fee the AER has calculated this on the total range of information provided. Table N.8 presents these revised calculations.

Table N.8 Cost of the committed bank loan facility

Item	CitiPower & Powercor updated submission	AER final decision
Establishment fee (basis points)	[c-i-c]	[c-i-c]
3–month Commitment fee (basis points)	[c-i-c]	[c-i-c]
Up–front cost (basis points)	[c-i-c]	[c-i-c]
Discount rate (%)	9.64	9.40
Unit rate (bppa)	**12.4**	**9.4–14.5**

Source: CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs"*, provided by email, 7 October 2010; AER analysis.

Note: The CitiPower & Powercor updated submission utilised an average establishment fee.

After adjusting for the CitiPower's and Powercor's nominal WACC and utilising the total range of establishment fees, the AER considers that the costs of the use of

80 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 22–24.

81 CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, p. 23.

committed bank loan facility is the range of 9.3–14.0 bppa. The AER notes that the CFO's witness statement stated that this option would also include additional costs for legal, internal and back costs. As noted above, the AER allows or determines the efficient and prudent costs required by a DNSP to manage refinancing risk. Therefore in comparison to its analysis of the underwriting volume only approach above, the AER considers that the committed bank loan facility is not an efficient approach and therefore is not consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast opex reasonably reflects the opex criteria.

Summary of Approaches

Table N.9 summarises the AER's conclusion on the costs of the three approaches considered in the CFO's witness statement, with appropriate revisions and updates.

Table N.9 Comparison of the cost of the approaches provided by CitiPower and Powercor submission and the AER final decision

Method	CitiPower & Powercor updated submission	AER final decision
Underwriting method (bppa)	N/A	4.0-7.9
Completion method (bppa)	15.9–17.9	14.2–16.2
Commitment method (bppa)	17.9	0–16.2
Cash reserves	19.6	18.5
Committed bank loan facility (bppa)	12.4	9.4–14.5

Source: CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010, pp. 23–24; CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs,* provided by email, 7 October 2010; AER analysis.

Based on the approaches in the CFO's witness statement, and taking account of the midpoint of each range, the AER considers that the reasonable estimate of efficient benchmark costs for a refinancing plan are based on the underwriting volume only method.

As stated above, the AER notes that the underwriting cost estimate based on the ACG method (7.14–7.31 bppa) falls within the AER revised cost range based on its analysis, albeit at the upper end of this range. The AER has decided to continue to use the ACG-derived estimate of 7.14–7.31 bppa for the underwriting component, noting that this is conservative relative to the midpoint of 5.9 bppa that would apply based on its analysis of the underwriting volume only method above. The AER considers that this advances both internal consistency–all components of the allowance are based on the same source–and regulatory consistency since this figure is based on the same method as applied in previous regulatory decisions.

N.4.2.5 AER conclusion

The AER considers that the Victorian DNSPs should be compensated for the efficient and prudent costs of a refinancing plan. However, consistent with its draft decision and based on its analysis and consideration of the issues above the AER does not consider that the allowance proposed by CitiPower and Powercor associated with early refinancing costs should be added to the direct debt raising costs allowance. The AER's analysis above demonstrates that the underwriting volume only method to early debt refinancing is the efficient and prudent approach. In comparison to its analysis of the underwriting volume only approach, the AER considers that the other methods evaluated above are not efficient approaches and therefore are not consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast opex reasonably reflects the opex criteria.

As previously stated, the costs and descriptions of the underwriting volume only method and the underwriting component in the ACG method are comparable. Therefore to include an additional underwriting early refinancing allowance would be double counting the costs of managing refinancing risk.

The AER considers that based on the ACG method the benchmark debt raising costs allowance already includes a reasonable estimate of the efficient and prudent costs of a refinancing plan and that no increase in these costs is required.

N.5 AER conclusion

This appendix has assessed the proposed allowance for debt raising costs which is one component of each Victorian DNSP’s proposed total forecast opex. The AER considers that the proposed bppa allowance assessed for JEN, SP AusNet and United Energy in this appendix is consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast opex reasonably reflects the opex criteria. The AER considers that the proposed bppa allowance assessed for CitiPower and Powercor in this appendix is not consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast opex reasonably reflects the opex criteria and accordingly has substituted this estimate. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs’ total forecast opex.

That constituent decision, which should be read together with this appendix, is discussed at Chapter 7.

As a result of the analysis of the Victorian DNSPs' revised regulatory proposals and submissions, the AER considers the debt raising allowances set out in Table N.10, and discussed below; represent the efficient and prudent costs that a network service provider in the circumstances of the respective DNSPs would require in the forthcoming regulatory control period.

Table N.10 AER conclusion of benchmark debt raising costs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	0.69	0.74	0.78	0.83	0.87	**3.91**
Powercor	1.16	1.24	1.32	1.39	1.46	**6.57**
JEN	0.44	0.46	0.48	0.50	0.52	**2.41**
SP AusNet	1.12	1.20	1.30	1.40	1.49	**6.49**
United Energy	0.74	0.80	0.85	0.88	0.90	**4.16**

Source: AER analysis.
Note: Numbers may not add due to rounding.

CitiPower has an opening RAB of $1.29 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of CitiPower's opening RAB is approximately $772.4 million (nominal). Based on the refined ACG method, CitiPower will require around 4 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.2 bppa for direct debt raising costs is a reasonable benchmark for CitiPower. This benchmark is multiplied by the debt component of CitiPower's opening RAB to provide an average allowance of $0.78 million per annum ($2010).

Powercor has an opening RAB of $2.21 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of Powercor's opening RAB is approximately $1.33 billion (nominal). Based on the refined ACG method, Powercor will require around 6 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.0 bppa for direct debt raising costs is a reasonable benchmark for Powercor. This benchmark is multiplied by the debt component of Powercor's opening RAB to provide an average allowance of $1.31 million per annum ($2010).

JEN has an opening RAB of $757million (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of JEN's opening RAB is approximately 454million (nominal). Based on the refined ACG method, JEN will require around 2 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.9 bppa for direct debt raising costs is a reasonable benchmark for JEN. This benchmark is multiplied by the debt component of JEN's opening RAB to provide an average allowance of $0.48 million per annum ($2010).

SP AusNet has an opening RAB of $2.07 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of SP AusNet's opening RAB is approximately $1.24 billion (nominal). Based on the refined ACG method, SP AusNet will require around 5 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.2 bppa for direct debt raising costs is a reasonable benchmark for SP AusNet. This benchmark is multiplied by the debt component of SP AusNet's opening RAB to provide an average allowance of $1.30 million per annum ($2010).

United Energy has an opening RAB of $1.38 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of United Energy's opening RAB is approximately $828 million (nominal). Based on the refined ACG method, United Energy will require around 4 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.2 bppa for direct debt raising costs is a reasonable benchmark for United Energy. This benchmark is multiplied by the debt component of United Energy's opening RAB to provide an average allowance of $0.83 million per annum ($2010).

O Equity Raising Costs

Equity raising costs, such as legal fees, marketing costs and other transaction costs, are incurred in raising new equity capital. These are upfront expenses, with little or no ongoing costs over the life of the equity. While the majority of the equity a firm will raise is typically obtained at its inception, there may be points in the life of a firm—for example, during capital expansion—where it chooses additional external equity funding (instead of debt or internal funding) as a source of capital, and accordingly may incur equity raising costs.

O.1 AER draft decision

Of the five Victorian DNSPs, only CitiPower, Powercor and Jemena electricity networks (JEN) requested equity raising costs in their initial regulatory proposals. In assessing their equity raising costs, the AER applied a benchmark cash flow analysis to determine the amount of funds available from retained earnings, the amount reinvested via dividend reinvestment plans and the amount of external equity required from seasoned equity offerings (SEOs). These components were added to determine the total benchmark equity raising costs for CitiPower, Powercor and JEN, as set out in Table O.1.

The benchmark cash flow analysis demonstrated that CitiPower and Powercor required a significantly lower amount of equity raising costs than their respective proposals while JEN had sufficient retained cash flows for its equity requirements. Consequently, the AER's draft decision refused to accept CitiPower's, Powercor's and JEN's proposed benchmark equity raising costs. No additional provisions were made for either indirect equity raising costs or costs associated with early equity raising costs.

Table O.1 AER draft decision on benchmark equity raising costs for the forthcoming regulatory control period

DNSP	Total equity raising costs (nominal)	Total equity raising costs ($'m, 2010)
CitiPower	2.7	2.5
Powercor	1.9	1.7
JEN	–	–

Source: AER, *Draft decision*, Appendix N, p. 300.

O.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs accepted the AER's draft decision on equity raising costs in their revised regulatory proposals. The revised equity raising costs proposed by the Victorian DNSPs are outlined in Table O.2:

Table O.2 Victorian DNSP revised proposals on benchmark equity raising costs ($'m, 2010)

DNSP	2011	2012	2013	2014	2015	Total
CitiPower	0.2	0.3	0.7	0.7	0.7	**2.5**
Powercor	–1.3	–0.7	0.0	0.8	1.5	**0.3**
JEN	–	–	–	–	–	**–**
SP AusNet	–	–	–	–	–	**–**
United Energy	0.2	0.2	0.5	0.6	0.6	**2.2**

Source: CitiPower, *Post tax revenue model*, July 2010; Powercor, *Post tax revenue model*, July 2010; JEN, *Post tax revenue model*, July 2010; SP AusNet, *Post tax revenue model*, July 2010; United Energy, *Post tax revenue model*, July 2010.

CitiPower and Powercor both noted in their revised regulatory proposals that they:

> …[do] not contest the AER's Draft Determination with respect to equity raising costs.[1]

CitiPower's and Powercor's revised regulatory proposals capitalised their equity raising costs.[2]

Similarly, JEN noted that it largely accepted the approach in the AER's draft decision.[3] JEN's revised regulatory proposal stated that based on its forecasts and assumptions, its equity raising requirements in the forthcoming regulatory control period will be funded through retained earnings. JEN noted that its only departure from the draft decision is an assumption of a 70 per cent dividend pay out ratio compared to the AER's assumption of 100 per cent. Notwithstanding this, JEN's revised regulatory proposal had enough retained earnings to fund its equity requirements.

Further, JEN proposed that where the AER's final decision departs from forecasts and assumptions in JEN's revised regulatory proposal, the AER should allow JEN to recover its equity raising costs accordingly.[4] If an allowance for equity raising costs is provided in the final decision, JEN proposed that it be capitalised to JEN's opening 2011 Regulatory asset base (RAB).

SP AusNet did not request equity raising costs in its initial regulatory proposal or its revised regulatory proposal.

United Energy included an allowance for equity raising costs in its post tax revenue model.[5] This was calculated using the same methodology as employed by the AER in

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1 CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 252; Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 242.
2 CitiPower, *Post tax revenue model*, July 2010; Powercor, *Post tax revenue model*, July 2010.
3 Jemena electricity networks (JEN), *Revised Regulatory Proposal 2011–15*, 20 July 2010, p. 194.
4 JEN, *Revised Regulatory Proposal*, p. 194.
5 United Energy, *Post tax revenue model*, July 2010.

its draft decision and, consistent with the other Victorian DNSPs, United Energy capitalised these costs.

O.3 Issues and AER considerations

O.3.1 Direct equity raising costs

O.3.1.1 AER draft decision

The AER accepted that equity raising costs for new issuance are a legitimate cost for a benchmark efficient firm only where equity funding is the least cost option available.[6] A DNSP should only be provided with an allowance for equity raising costs where cheaper sources of funding, such as retained earnings, are insufficient, subject to the gearing ratio and other assumptions about financing decisions being consistent with regulatory benchmarks.

The AER considered the Victorian DNSPs' proposals and submissions and rejected the alternative estimates of direct equity raising costs proposed on the grounds that they deviated substantially from the equity raising conditions relevant to the benchmark firm. In particular the AER did not accept the proposals for either indirect equity raising costs or costs associated with the early equity raising costs. Based on its detailed analysis, the AER considered that the best estimate of the direct costs of raising equity varies depending on the method employed:

- 0 per cent of equity obtained via retained earnings
- 1 per cent of equity obtained via dividend reinvestment plans
- 3 per cent of equity obtained via external SEOs (placements and rights issues).

O.3.1.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs accepted the AER's draft decision.

CitiPower and Powercor accepted the draft decision in its entirety.[7] JEN accepted the draft decision and noted that, based on its revised regulatory proposal forecast and assumptions, it will be able to fund its equity raising costs through retained earnings.[8] United Energy requested an allowance for equity raising costs utilising the methodology employed in the AER's draft decision.[9]

O.3.1.3 Issues and AER considerations

The AER notes that the Victorian DNSPs did not raise any new arguments regarding equity raising costs in their revised regulatory proposals. The AER notes that the arguments made by the Victorian DNSPs in their initial proposals on equity raising

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6 AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Final decision, 14 June 2007, p. 100; AER, *SP AusNet transmission determination 2008–09 to 2013–14*, Final decision, 31 January 2008, p. 144; AER, *ElectraNet transmission determination 2008–09 to 2013–14*, Final decision, 11 April 2008, p. 88.

7 CitiPower, *Revised regulatory proposal*, p. 252; Powercor, *Revised regulatory proposal*, p. 242.

8 JEN, *Revised Regulatory Proposal*, p. 194.

9 United Energy, *Post tax revenue model*, July 2010.

costs, including consultant reports and submissions were addressed by the AER in the draft decision.

The AER also notes that United Energy's proposed equity raising costs utilises the methodology employed by the AER in its draft decision.

The AER has assessed the benchmark equity raising costs of the Victorian DNSPs and is satisfied that the forecast expenditure reasonably reflects the capex criteria in National Electricity Rules (NER), and in doing so has had regard to the capex factors.[10]

O.3.1.4 AER conclusion

Based on the AER's detailed analysis and consideration in the draft decision, and because no new information or arguments were provided in the Victorian DNSPs' revised regulatory proposals, the AER considers that the methodology employed by the AER in its draft decision is appropriate for estimating benchmark equity raising costs.

O.4 AER conclusion

Consistent with the draft decision, the AER considers that the best estimate of the direct costs of raising equity varies depending on the method employed:

- 0 per cent of equity obtained via retained earnings
- 1 per cent of equity obtained via dividend reinvestment plans
- 3 per cent of equity obtained via external SEOs (placements and rights issues).

For each Victorian DNSP, the AER will apply the benchmark cash flow analysis to determine the amounts that will be available from retained earnings, the amounts reinvested via dividend reinvestment plans and the amount of external equity required for the forthcoming regulatory control period from SEOs (placements and right issues). Each component will be summed and amortised over the weighted average standard life of the Victorian DNSPs' RABs to provide the equity cost allowance associated with forecast capex in the forthcoming regulatory control period.

The AER's conclusion on benchmark equity raising costs through applying the benchmark cash flow analysis determines that JEN has sufficient retained cash flows for their respective equity requirements. Therefore, no benchmark equity raising cost allowances have been provided to these DNSPs for the forthcoming regulatory control period. For CitiPower, Powercor, SP AusNet and United Energy, the benchmark cash flow analysis determines that an equity raising cost allowance is required for the forthcoming regulatory control period which is set out in Table O.3.

The AER is satisfied that the forecast expenditure reasonably reflects the capex criteria in NER, and in doing so has had regard to the capex factors.[11]

10 NER, cll. 6.5.6(c)(1); 6.5.6(c)(2); 6.5.6(e)(4).
11 NER, cll. 6.5.6(c)(1); 6.5.6(c)(2); 6.5.6(e)(4).

Table O.3 AER final decision on benchmark equity raising costs ($'m, nominal)

Cash flow analysis	**CitiPower**	**Powercor**	**SP AusNet**	**United Energy**	**Notes**
Dividends	170.2	330.6	127.4	244.4	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	51.1	99.2	38.2	73.3	30% of dividends paid
Cost of dividend reinvestment plans	0.5	1.0	0.4	0.7	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	822.7	1 420.2	1 508.1	803.9	This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment)
Debt component	388.1	655.5	756.9	325.7	Set to equal 60% of RAB increase (not capex)
Equity component	434.7	764.7	751.2	478.2	Residual of capex funding requirement and debt component
Retained cash flow available for reinvestment	342.4	569.7	704.7	368.0	Includes dividends reinvested
External equity requirement	92.3	195.0	46.5	110.2	Equal to equity component less retained cash flows
External equity raising costs	2.8	5.9	1.4	3.3	External equity requirement multiplied by benchmark direct cost (3%)
Total equity raising costs	3.3	6.9	1.8	4.0	Sum of dividend reinvestment plan cost and external equity raising cost
Total equity raising costs ($'m, 2010)	**3.0**	**6.3**	**1.8**	**3.7**	**To be added to the RAB at the start of their forthcoming regulatory control period**

Source: AER analysis.
Note: Numbers may not add due to rounding.

P Capital Expenditure

This appendix outlines the AER's detailed assessment undertaken for its final decision on the following capital expenditure (capex) categories; new customer connections, reinforcement, reliability and quality maintained, environment, safety and legal, SCADA and network control, non-network IT, and non-network other. A high level summary of this assessment is included in the capital expenditure chapter (chapter 8) of this final decision.

P.1 New customer connections

The new customer connections category included in standard control capital expenditure includes capital expenditure related to all connections where augmentation of supply is required. Customer contributions are calculated based on the requirements under the Victorian Electricity Industry Guideline No. 14 (guideline 14). Customer contributions are removed from gross expenditure to determine the net capital customer connections expenditure for the forthcoming regulatory control period.

P.1.1 AER approach

The AER undertook a review of historical and forecast gross capex and net capex (and therefore the percentage of customer contributions), the gross unit cost and the number of customer connections to determine whether the forecast new customer connections capex is consistent with the capex requirements of the NER. To assist with this review of new customer connections, the AER requested that the Victorian DNSPs provide a breakdown of customer connections expenditure and connection numbers by customer type for the 2006–10 and 2011–15 regulatory control periods. The AER also sought further explanation from the Victorian DNSPs where significant changes from actual historical data were being forecast, resulting in significant increases in net capex.

As noted at the beginning of the capex chapter, each Victorian DNSP proposed an allowance for new customer connections capex as a component of their total proposed forecast capital expenditure for the 2011–15 regulatory control period. The assessment of that reinforcement is relevant to determining whether the AER is satisfied that the total proposed forecast capital expenditure or its estimate of the required capital expenditure reasonably reflects the capital expenditure criteria.

Specifically, this appendix assesses the proposed allowance and what the level of efficient expenditure for new customer connections which a prudent operator, in the circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capital expenditure objectives.

In determining whether each of the Victorian DNSPs’ proposed new customer connections forecast capex reasonably reflects the capex criteria, the AER has had regard to the capex factors as relevant, in particular:

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals

- capex factor (2) – taking account submissions received from stakeholders
- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (5) – taking into account the actual and expected capex during any preceding regulatory control periods
- appendix H to this final decision sets out the AER's analysis—which benchmarks the Victorian DNSPs against their interstate counterparts including benchmarking the DNSPs' forecasts against the AER's forecasts—and is to be read in conjunction with this appendix.

The AER has compared the actual capex incurred during the 2006–10 and previous regulatory control periods against the DNSPs' proposed capex and the AER's estimate of the required capex for the forthcoming regulatory control period taking into account any observed trends in actual capex.

P.1.2 AER draft decision

In the draft decision, the AER assessed the historical and forecast gross customer connections and forecast customer contributions.

For CitiPower and Powercor, the AER concluded that their proposed forecasts should be adjusted to be consistent with historical trend. Proposed capex related to alternative control services was also removed. For JEN, SP AusNet and United Energy, the AER concluded that their proposed gross new customer connections capex were consistent with historical trend and were therefore found to be reasonable.

In the draft decision the AER also requested each DNSP's comments in taking into account the requirements of Guideline 14 in forecasting customer contributions.

P.1.3 Victorian DNSP revised regulatory proposals

Table P.1 sets out the Victorian DNSPs' revised regulatory proposal for forecast new customer connections gross capital expenditure and customer contributions.

Table P.1 Victorian DNSPs' proposed new gross customer connections capex customer contributions ($'m, 2010)

		2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	Gross	218.7	44.6	45.6	45.6	46.1	46.6	228.6	5%
	Net	115.1	35.0	34.7	34.6	34.5	34.3	173.1	50%
Powercor	Gross	556.4	114.9	114.9	115.0	115.0	115.0	574.9	3%
	Net	273.8	72.7	71.7	70.9	70.4	69.9	355.7	30%
JEN	Gross	117.6	23.1	23.0	27.7	29.7	33.0	136.6	16%
	Net	71.6	15.9	15.9	19.6	21.8	24.5	97.8	36%
SP AusNet	Gross	337.6	79.9	78.1	73.8	69.6	71.3	372.7	10%
	Net	217.4	69.7	68.1	64.3	60.7	62.2	325.0	50%
United Energy	Gross	176.0	49.8	48.7	48.3	46.8	45.0	238.6	36%
	Net	107.6	22.2	21.6	21.8	20.1	19.0	104.6	-2.7%
Total	**Gross**	**1406.3**	**312.3**	**310.4**	**310.4**	**307.3**	**311.0**	**1551.4**	**10.3%**
	Net	**785.5**	**215.5**	**212.1**	**211.3**	**207.5**	**209.8**	**1056.2**	**34.5%**

Note: Gross connections capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower, Revised regulatory proposal, RIN templates 2.1, Powercor Revised regulatory proposal, RIN templates 2.1, JEN Regulatory Proposal, RIN templates 2.1, SP AusNet, Revised regulatory proposal, RIN templates 2.1, United Energy Revised regulatory proposal, templates 2.1.

Regarding gross customer connections, CitiPower and Powercor accepted the AER's draft decision that historical costs should be used to form a basis for forecasts of new customer connections. CitiPower and Powercor therefore revised their forecasts based on an average of historical costs for 2005 to 2009.[1]

CitiPower and Powercor forecast customer contributions for each of those customer connections categories that are likely to be affected by a change in the algebraic parameters including the MCR, Po, X factor and WACC.[2]

JEN revised its forecast new customer connections based on revised customer numbers forecast by NIEIR and business activity forecast by the Construction Forecasting Council. This has resulted in an increase in forecast customer connections capex. Regarding customer contributions, JEN has revised its forecasts based on the requirements of guideline 14 in the calculation of customer incremental revenue.[3]

1 CitiPower, *Revised regulatory proposal*, p.260; Powercor, *Revised regulatory proposal*, p.250.
2 CitiPower, *Revised regulatory proposal*, p.260; Powercor, *Revised regulatory proposal*, p.250.
3 JEN, *Revised regulatory proposal*, p.146.

SP AusNet accepted the AER's draft decision on gross customer connections, however, it has updated its forecast gross customer connections capex to reflect NIEIR's revised customer connections forecasts. Regarding customer contributions SP AusNet has revised its forecasts based on the requirements of guideline 14 in the calculation of customer incremental revenue.[4]

United Energy accepted the AER's draft decision. However, it has updated its forecast based on revised energy and customer number forecasts. It did not however update its forecast customer contributions to be consistent with the requirements of guideline 14.[5]

P.1.4 Issues and AER considerations

P.1.4.1 CitiPower and Powercor

Gross connection capex

In the AER's draft decision, CitiPower's and Powercor's gross new customer connections were adjusted where there were significant increases from historical trend. The AER also removed proposed capex that it considered to be alternative control services including, customer supply negotiations, labour and materials for routine connections, meter installation costs and temporary supply services.

CitiPower and Powercor accepted the AER's approach to forecasting new customer connections in the draft decision, and based their revised regulatory proposals on historical costs for 2006–09.

CitiPower and Powercor did not agree with the AER's classification of forecast capex relating to miscellaneous connection services. However, CitiPower and Powercor considered that the AER made an error in removing function codes 114 and 115 from the standard control forecast capex standard control services and allocating them to alternative control services. This was because:

- function codes 114 and 115 capture the costs of miscellaneous customer connection services
- these costs are a customer connections capex and not a routine connection
- CitiPower's CAM classifies these costs as standard control.[6]

Based on CitiPower's and Powercor's revised regulatory proposal, and the additional information they provided, the AER accepts that capital expenditure for miscellaneous connection services are standard control services. The AER has therefore accepted CitiPower's and Powercor's revised regulatory proposal on gross connections capex related to miscellaneous connection services.

CitiPower and Powercor did not agree with the AER's draft decision on embedded generation connections. CitiPower stated in its revised regulatory proposal that it

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4 SP AusNet, *Revised regulatory proposal*, p.155.
5 United Energy, *Revised regulatory proposal*, p.128.
6 CitiPower, *Revised regulatory proposal*, p.263; Powercor, *Revised regulatory proposal*, p.253.

expects to receive a number of requests for these connection types.[7] The AER considers that, given the proposed expenditure is forecast to be 100 per cent customer funded, and that CitiPower derived its forecasts taking into account known and likely customer connection requests, the forecast gross expenditure related to embedded generator connections is reasonable, consistent with the capex criteria.

The AER accepts CitiPower's and Powercor's revised new customer connections gross capital expenditure as being prudent and efficient, consistent with the requirements of the capex criteria. This assessment has taken into account the relevant capex factors, described above in section P.1.1

Customer contributions

CitiPower's and Powercor's revised forecast customer contributions proposals take into account the requirements of guideline 14, including updating for the proposed Po, X-factor and WACC outlined in their revised regulatory proposals. CitiPower and Powercor also revised their customer contributions based on the revised MCR rates. CitiPower and Powercor provided models to show how these parameters have been included in their forecast customer contributions.[8]

The AER has reviewed the revised methodology proposed by CitiPower and Powercor and found that it addresses the concerns which were raised by the AER in the draft decision. Accordingly, the AER accepts the methodology used by CitiPower and Powercor to determine their forecast customer contributions. The AER has used the methodology proposed by CitiPower and Powercor to determine forecast customer contributions consistent with the requirements of guideline 14, and has adjusted for the AER's final decision on CitiPower's and Powercor's Po, X-factors and the real pre-tax WACC.

P.1.4.2 JEN

Gross connection capex

In the draft decision, the AER accepted JEN's proposed gross connections capex as a reasonable forecast consistent with the requirements of the NER.

JEN revised its forecast new customer connections based on revised customer numbers forecast by NIEIR, and business activity forecast by the Construction Forecasting Council.[9] This has resulted in an increase in forecast customer connections capex from the draft decision of $11 million over the forthcoming regulatory period.

In this final decision, the AER has retained its draft decision on new customer connections and has revised the forecast capex to account for the updated customer numbers proposed by JEN. The AER also considers that JEN's revised regulatory proposal is reasonably consistent with its historical expenditure for new customer connections capex.

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7 CitiPower, *Revised regulatory proposal*, p. 263.

8 CitiPower, *Revised regulatory proposal - Attachment 8 Customer contributions model*; Powercor, *Revised Proposal - Attachment 8 Customer contributions model*.

9 JEN, *Revised regulatory proposal*, p. 146.

Therefore, the AER accepts JEN's revised regulatory proposal for gross new customer connections as being the efficient costs to achieve the capex objectives, specifically to meet the expected demand for standard control services.

Customer contributions

JEN's revised regulatory proposal provided a model to calculate forecast customer contributions based on the revised impact of the Po, WACC and the X-factor in the forthcoming regulatory period.

The AER has assessed JEN's approach to calculating customer contributions for the forthcoming regulatory control period and considers it to be reasonable. Therefore the AER has accepted the approach. The AER has used the methodology proposed by JEN to determine forecast customer contributions, and has adjusted the calculation of customer contributions to incorporate the AER's final decision on JEN's Po, X-factors and real pre-tax WACC.

P.1.4.3 SP AusNet

Gross connection capex

In the draft decision the AER accepted SP AusNet's gross new customer connections net capital expenditure as part of the forecast capital expenditure allowance.

SP AusNet's revised regulatory proposal accepted the AER's draft decision on gross customer connections, however, it has updated its forecast gross customer connections capex to reflect NIEIR's revised customer connections forecasts.[10] This results in an increase in forecast customer connections capex from the draft decision of $15.7 million over the forthcoming regulatory period.

In this final decision the AER has retained its draft decision on new customer connections and has revised the forecast capex to accounts for the updated customer numbers consistent with SP AusNet's revised regulatory proposal. The AER also considers that SP AusNet's revised regulatory proposal is reasonably consistent with its historical expenditure for new customer connections capex.

The AER assessed SP AusNet's forecast new customer connections capex and considers that SP AusNet's forecasts take into account the change in growth in customer numbers for the forthcoming regulatory control period. The AER also considers that the revised regulatory proposal is consistent with historical trends in new customer connections capex.

Therefore, the AER accepts that SP AusNet's revised regulatory proposal for gross new customer connections outline the efficient costs to achieve the capex objectives, specifically to meet the expected demand for standard control services.

Customer contributions

The AER notes that SP AusNet has provided a model to calculate forecast customer contributions based on the revised impact of the Po, WACC and the X-factor in the forthcoming regulatory control period. The revised inputs have been factored into the

10 SP AusNet, *Revised regulatory proposal*, p.155.

AER's calculation of customer contributions for residential and business supply projects.

The AER has reviewed SP AusNet's approach to calculating customer contributions for the forthcoming regulatory control period and considers it to be reasonable. The AER has used the methodology proposed by SP AusNet to determine forecast customer contributions, adjusted for the AER's final decision on SP AusNet's Po, X-factors and the real pre-tax WACC.

P.1.4.4 United Energy

Gross connection capex

In the draft decision the AER accepted United Energy's gross new customer connections net capital expenditure as part of the forecast capital expenditure allowance.

United Energy accepted the AER's draft decision on gross customer connections in its revised regulatory proposal, however it has updated its forecast gross customer connections capex to reflect NIEIR's revised customer connections forecasts.[11] This results in an increase in forecast gross customer connections capex from the draft decision of $24.3 million over the forthcoming regulatory period.

The AER has retained its draft decision on new customer connections and has revised the forecast capex to accounts for the updated customer numbers consistent with United Energy's revised regulatory proposal. The AER considers that United Energy's revised regulatory proposal is reasonably consistent with its historical expenditure for new customer connections capex.

Based on the AER's assessment of United Energy's forecast new customer connections capex, the AER considers that United Energy's forecasts take into account the change in growth in customer numbers for the forthcoming regulatory control period. The AER also considers that the revised regulatory proposal is consistent with historical trends in new customer connections capex.

Therefore, the AER accepts United Energy's revised regulatory proposal for gross new customer connections as being the efficient costs to achieve the capex objectives, specifically to meet the expected demand for standard control services.

Customer contributions

United Energy did not take account the requirements of guideline 14 in its calculation of forecast customer contributions in its revised regulatory proposal. However, the AER considers that the revised forecast is consistent with historical trend. The AER therefore finds United Energy's revised regulatory proposal for customer contributions to be reasonable. However, the AER notes that United Energy will be required to calculate customer contributions consistent with the requirements of guideline 14 during the forthcoming regulatory control period.

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11 United Energy, *Revised regulatory proposal*, p.127.

P.1.4.5 AER conclusion

Table P.2 sets out the AER's conclusions on the Victorian DNSPs' proposed capex for new customer connections, for the forthcoming regulatory control period. In reaching its conclusion the AER has, in accordance with the requirements of the NER and guideline 14, considered the information provided in the regulatory proposals and later material provided to clarify the interpretation of the proposals, submissions received, its own analysis and the actual and expected capex of the DNSP in the current regulatory control period. Although the AER also considered whether an appropriate benchmark could be established for this activity, the AER found that insufficient data existed to set a reliable benchmark.

Table P.2 AER conclusion on new gross and net customer new customer connections ($'m, 2010)

		2011	2012	2013	2014	2015	Total
CitiPower	Gross	44.6	45.6	45.6	46.1	46.6	228.6
	Net	33.5	33.2	33.1	33.0	32.8	165.7
Powercor	Gross	114.9	114.9	115.0	115.0	115.0	574.9
	Net	67.3	66.7	66.1	65.8	65.4	331.2
JEN	Gross	23.1	23.0	27.7	29.7	33.0	136.6
	Net	15.8	15.7	19.5	21.7	24.3	97.0
SP AusNet	Gross	79.9	78.1	73.8	69.6	71.3	372.7
	Net	65.9	64.5	61.1	57.8	59.2	308.5
United Energy	Gross	49.8	48.7	48.3	46.8	45.0	238.6
	Net	22.2	21.6	21.8	20.1	19.0	104.6
Total	**Gross**	**312.3**	**310.4**	**310.4**	**307.3**	**311.0**	**1551.4**
	Net	**204.6**	**201.8**	**201.6**	**198.3**	**200.7**	**1007.0**

Note: Gross connections capex amounts are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

P.2 Reinforcement

DNSPs undertake reinforcement capital expenditure in order to meet the growing demand on the network. Reinforcement expenditure involves augmentation of network components to ensure they have sufficient capacity to meet high peak demand days. Reinforcement expenditure largely consists of augmentation of zone substations or establishing new zone substations, upgrading sub-transmission lines, 22kV distribution feeders and upgrading or establishing new distribution substations.

P.2.1 Approach

As noted in section 8.6.1 of the capex chapter, each Victorian DNSP proposed an allowance for reinforcement capex as a component of their total proposed forecast capital expenditure for the 2011–15 regulatory control period. The assessment of that reinforcement capex is relevant to determining whether the AER is satisfied that the total proposed forecast capital expenditure or its estimate of the required capital expenditure reasonably reflects the capital expenditure criteria.

Specifically, this section assesses the proposed allowance and what the level of efficient expenditure for reinforcement which a prudent operator, in the circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capital expenditure objectives.

This assessment is consistent with the capex criteria and the AER approach to assessing reinforcement outlined in section 8.6.1 of chapter 8 to the final decision. This assessment has had particular regard to:

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals
- capex factor (3) – whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting
- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (5) – taking into account the actual and expected capex during any preceding regulatory control periods. This process involved investigating the policies, procedures, and forecasting methodologies associated with the targeted matters and consideration of options other than major augmentation (that is, deferrals)
- capex factor (10) – where the AER has taken into account the extent to which each Victorian DNSP has considered and made provision for efficient, non-network alternatives.

As is discussed further in this appendix, the AER also considers that the capex factors specifically relevant to this assessment include:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period[12]
- where the DNSPs' forecast reinforcement capex was significantly greater than actual capex incurred during the previous and current regulatory control periods, the AER also further investigated the policies, procedures, and forecasting methodologies associated with the targeted matters, whether there is a justifiable need for the proposed investment and whether reasonable options were considered

[12] NER clause 6.5.7(e)(4).

other than major augmentation (that is, deferrals) and the most efficient outcome selected to satisfy that need. the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods[13]

- the extent to which the DNSP has considered, and made provision for, efficient non-network alternatives, whether other non-network alternatives have been adequately considered in as part of the proposed forecast reinforcement capital expenditure.[14]

In conducting this assessment, the AER assumed the current level of capex to be a representation of an efficient base to forecast augmentation expenditure.

Appendix H should also be read in conjunction with this appendix. It sets out the AER's analysis which benchmarks the Victorian DNSPs against their interstate counterparts including benchmarking the DNSPs' forecasts against the AER's forecasts to assess the efficient level of reinforcement capex for the forthcoming regulatory control period.

The AER's analysis of the Victorian DNSPs proposed reinforcement capex recognises that electricity network planning by Victorian distributors generally incorporates a probabilistic planning approach. Probabilistic planning is a form of cost-benefit analysis which seeks to measure the cost to consumers of the failure to serve a need for energy relative to the value customers place on receiving that service. Importantly, a deterministic planning framework is commonly used in other jurisdictions including New South Wales and Queensland. Therefore, reinforcement investment decisions in other jurisdictions will differ because of this difference in planning approach.

Under the probabilistic planning approach, if the cost of an augmentation to ensure the need for energy is served is less than the value to customers of that energy then the proposed augmentation should proceed. The key measure in this analysis is termed 'expected unserved energy' (EUSE) which is measured in megaWatt hours (MWhrs). In turn, EUSE is derived from a calculation of energy-at-risk (EAR), taking into account asset rating, the load growth profile and the probability of failure of the assets under study.

To ascertain the economic value of EUSE the estimated EUSE is multiplied by a value termed the 'value of customer reliability' (VCR) which has units of $ per MWhr. VCR is estimated by periodic surveys of customers in different load categories (i.e. residential, commercial, light industrial, heavy industrial, etc.) to arrive at values typical for that customer category. These values are normally combined to arrive at a weighted mean value for general planning purposes. The current (mean) value of VCR as used by the Australian Energy Market Operator (AEMO) for planning purposes is nominally $55,000 per MWhr. Note that the value of VCR used in a particular analysis should be that which is appropriate for the mix of customers utilising the distribution assets being considered. Where a particular customer profile is known at a substation it is reasonable to assess VCR based on the actual customer

13 NER clause 6.5.7(e)(5).
14 NER clause 6.5.7(e)(10).

profile rather than apply an average value. VCR is also known by the alternative name 'VoLL' – meaning 'Value of Lost Load'.

The product of EUSE and VCR is an economic measure in dollars of the expected value to customers of an augmentation. If this figure exceeds the cost of augmentation then an economic benefit is demonstrated and the augmentation is an economically justified option. Probabilistic planning therefore only augments the network where the likely value to customers of an enhancement warrants the augmentation and not simply on a fixed concept of customer reliability. Note that this analysis is tied to the specific event being studied. Also, an economically justified option may alleviate but not remove all of the EUSE.

For this investigation the AER instructed its consultant, Nuttall Consulting to review each DNSPs forecasts in accordance with this economic framework which is reflective of this form of network planning. Nuttall Consulting was required to consider whether the DNSP had considered a reasonable range of alternative options in accordance with the capex factors (NER cl. 6.5.7(e) (10)) and whether the load profiles and planning assumptions were a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives and if not, to advise an alternative view of the minimum change necessary to make the DNSPs proposal compliant with the NER.

Where Nuttall Consulting reviewed the planning approach of each DNSP and found that their calculations of the probability of failure and the values of VCR used in their calculations were sound, the AER accepted the DNSPs calculations of these parameters as sound. However, Nuttall Consulting has reported that in some cases, taking into account the load profiles used by the DNSPs over-estimates the energy-at-risk, or load transfers are not being fully taken into account. Consequently, in a number of instances, an augmentation appears justified earlier than should otherwise be the case. Specific findings are discussed further in relation to each Victorian DNSP in the sections below.

P.2.2 AER draft decision summary

Taking into account Nuttall Consulting's detailed methodological and project reviews the AER in its draft decision found that the proposed reinforcement capex forecasts were not shown to provide a reasonable and efficient forecast of reinforcement capex needs. In the absence of justified increases in reinforcement forecasts, the AER considered that further emphasis should be given to historical trends.

In estimating the required forecast reinforcement capital expenditure that reasonably reflects the capital expenditure criteria for each Victorian DNSP, the AER adopted the recommendations by Nuttall Consulting, based on its weighted probability analysis. Table P.3 outlines the AER's draft decision on reinforcement capex for the Victorian DNSPs for the forthcoming regulatory control period.

Table P.3 AER draft decision on reinforcement capex for Victorian DNSPs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	39.6	32.4	36.5	11.2	11.9	131.5
Powercor	26.4	28.1	29.9	31.7	33.7	149.8
JEN	10.1	10.9	11.8	12.7	13.7	59.1
SP AusNet	28.3	31.0	33.8	36.9	40.3	170.3
United Energy	24.7	25.2	25.7	26.2	26.7	128.4
Total	**129.2**	**127.5**	**137.6**	**118.7**	**126.3**	**639.2**

Note: These numbers are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

P.2.3 Victorian DNSP revised regulatory proposals summary

None of the Victorian DNSPs accepted the draft decision on reinforcement capex. In their revised regulatory proposals, each Victorian DNSP largely proposed reinforcement capex consistent with their initial regulatory proposals as outlined in table p.4.

Table P.4 Victorian DNSPs' revised regulatory proposal reinforcement capex comparison—direct costs ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total
CitiPower	62.8	45.1	48.3	58.5	46.5	32.7	231.2
Powercor	123.6	43.5	44.1	47.9	48.5	52.5	236.4
JEN	52.1	17.7	22.1	22.2	23.1	21.9	107.1
SP AusNet	156.0	66.8	70.3	89.2	58.1	75.1	359.5
United Energy	130.1	45.0	48.2	49.5	40.9	30.4	214.1
Total	**524.5**	**218.1**	**233.1**	**267.4**	**217.1**	**212.6**	**1148.2**

Note: These numbers are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

Table P.5 compares the Victorian DNSPs' initial and revised regulatory proposals and the AER's draft decision for forecast reinforcement capital expenditure.

Table P.5 Victorian DNSPs' revised regulatory proposal reinforcement capex comparison—direct costs ($'m, 2010)

	Initial proposal	Draft decision	Revised proposal
CitiPower	229.4	131.5	231.2
Powercor	241.5	149.8	236.4
JEN	143.3	59.1	107.1
SP AusNet	321.2	170.3	359.5
United Energy	205.0	128.4	214.1
Total	**1140.4**	**639.2**	**1148.2**

Note: These numbers are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

None of the Victorian DNSPs agreed with Nuttall Consulting's weighted probability analysis which the AER applied in the draft decision. The Victorian DNSPs submitted it was a subjective and an untested methodology and did not take account of a statistically significant sample of projects. Specifically, issues were raised in respect of Nuttall Consulting's conclusions on the use of old load profiles, impact of maximum demand on delaying projects and the claims there was a lack of detailed economic analysis by the Victorian DNSPs.

The Victorian DNSPs, in their revised regulatory proposals, have provided further information for those projects reviewed by Nuttall Consulting. For the majority of projects reviewed by Nuttall Consulting, the DNSPs submitted that the additional information should justify a 100 per cent probability of proceeding in the forthcoming regulatory control period.

P.2.4 Submissions

Total Environment Centre stated in its submission that:

> The Nuttall Consulting Report on capex has not properly considered DM, contradicting the AER's claim that the report involved 'examining whether each Victorian DNSP has considered, and made provision for, efficient non-network alternatives. Instead only one proposed DM project has been considered by the Nuttall report. It is sadly ironic that while Nuttall and the AER conclude that many of the proposed augmentations were overblown and premature and could be deferred, there has been no consideration of whether these and other augmentations could be deferred by DM.[15]

The AER acknowledges the concerns raised by the Total Environment Centre, and has aimed to ensure that alternative non-network options have been considered as part of its assessment of forecast reinforcement capital expenditure.

In comparison to their initial regulatory proposals, the Victorian DNSPs have provided further economic justification as part of their revised regulatory proposals.

15 TEC, *Submission to the AER on draft decision Victorian DNSPs 2011-2015*, p.4.

The AER has examined these justifications, including the supporting documentation provided, to ascertain whether those DNSPs consider demand management in their planning processes. JEN, SP AusNet and United Energy clearly do so, albeit the level of consideration in many instances would suggest that some DNSPs regard demand-side alternatives more viable as interim support measures rather than as longer term alternatives.

P.2.5 Issues and AER considerations

P.2.5.1 Approach to assessment of reinforcement capex

As noted above, in its draft decision the AER was not satisfied that each DNSP's initial regulatory proposal of reinforcement expenditure represented a reasonable forecast that was consistent with the capex criteria. In estimating the required forecast, the AER applied Nuttall Consulting's recommended weighted probability assessment.

Revised proposals

In their revised regulatory proposals CitiPower and Powercor argued that Nuttall Consulting's forecasting methodology was flawed because:

- the forecasts are not linked to maximum demand forecasts
- the weighted probability analysis results are heavily reliant on engineering judgement and
- it is not reasonable to extrapolate the probabilities for the major projects reviewed across CitiPower's and Powercor's reinforcement capex.[16]

JEN argued, in its revised regulatory proposal, that the average weighted probability approach does not attempt to assess the proposed expenditure against the capex objectives or capex criteria. Further JEN considered that the approach does not have adequate regard to the forward looking nature of the capex objectives and criteria and that the AER draft decision does not appear to be consistent with clause 6.12.3(f).[17]

SP AusNet did not accept the 53 per cent probability assessment on the basis the reviewed projects are not a representative sample of the entire program. Further, SP AusNet considered that Nuttall Consulting's methodology fails to fulfil some of the main criteria SP AusNet consider should attach to a sound forecasting methodology namely, objectivity, transparency and repeatability.[18]

SP AusNet submitted that Nuttall Consulting's report did not explain how the assignment of probability for individual projects was made, and how someone could repeat the results of its analysis, as it relies on subjective judgement. SP AusNet also submitted that the AER ignored the historical upward trend in reinforcement expenditure in 2009 and 2010.[19]

[16] CitiPower, *Revised regulatory proposal*, p.268; Powercor, *Revised regulatory proposal*, p.257.
[17] JEN, *Revised regulatory proposal*, pp. 147-148.
[18] SP AusNet, *Revised regulatory proposal*, p.102.
[19] SP AusNet, *Revised regulatory proposal*, p.103.

SP AusNet informed that it had undertaken a top down analysis to test the veracity of the proposed reinforcement program. SP AusNet considers that historic level of expenditure cannot be maintained without compromising network reliability, as SP AusNet project load at risk in key areas of the network to grow exponentially unless addressed with large scale investment.[20]

In its revised regulatory proposal United Energy did not accept the AER's draft decision on reinforcement capex, in particular that only 63 per cent of the budget has been justified and the methodology used in arriving at that conclusion. United Energy submitted that Nuttall Consulting arbitrarily cut its proposed program based on an over-simplified assessment of a limited number of projects.[21]

In response, United Energy submitted that all the projects reviewed by Nuttall Consulting are well justified by the strategy planning papers. United Energy also stated that the fact that it will spend its reinforcement budget allocated in the present regulatory control period indicates that its planning procedures provide a reasonable assessment of the required reinforcement expenditure.[22]

Consultant review

Nuttall Consulting considered that the Victorian DNSPs misrepresented the process it undertook in reviewing the initial regulatory proposals. Nuttall Consulting considered that its probabilities were based on a detailed review of the information on each project, including:

- the expected energy at risk and/or the value of other benefits driving the project
- whether the options considered were economic.[23]

Nuttall Consulting considered that it followed an objective assessment of the material to determine the factors that may result in the deferral of the project or a lower cost option being selected. This included an assessment of whether the timing would result in a net benefit, and when this may be maximised. Nuttall Consulting also noted that it took into account higher level findings, but it considered that its assessment was consistent with the NER capex criteria and the capex factors. [24]

Regarding its process, Nuttall Consulting considered that this approach of defining probabilities is a pragmatic and robust approach to producing an overall capex allowance. Regarding the number of projects reviewed, Nuttall Consulting acknowledged that while only a limited number of projects were reviewed for each DNSP, it considered the number to be reasonable. Nuttall Consulting considered that the number of projects reviewed was a large enough portion of expenditure to gain a conservative view of the expenditure needs in the broader context of its review findings. For SP AusNet, Nuttall Consulting acknowledged that the projects selected did not adequately represent projects in the first half of the regulatory control period.

20 SP AusNet, *Revised regulatory proposal*, p.103.
21 United Energy, *Revised regulatory proposal*, p.126.
22 United Energy, *Revised regulatory proposal*, p.126.
23 Nuttall Consulting, *Victorian Electricity Distribution Price Review - Capital Expenditure Review -- Revised Proposals*, October 2010, p.23.
24 ibid., p.24.

Nuttall Consulting has included a number of additional projects in its assessment that are forecast in the first half of the regulatory control period.[25]

Nuttall Consulting also considered that its review did not result in a downward bias, where projects were given a probability of 90 per cent. It considered that based on its high level findings, consistent over forecasting by the DNSPs and other methodological input issues, a reduced probability was reasonable.[26]

AER considerations

The AER acknowledges the concerns regarding the use of the Nuttall Consulting's weighted probability assessment. However the AER considers that Nuttall Consulting's assessment of the proposed reinforcement expenditure forecasts is justified as it is based on a detailed assessment of the methodologies, key input assumptions in addition to the detailed project reviews. The AER therefore considers that this approach to assessing reinforcement capex reasonably tests the prudency and efficiency of the reinforcement expenditure forecast, taking into account the relevant capex factors.

The AER acknowledges that further detail could have been provided in its review on the development of the probabilities that were applied in the draft decision. The AER notes that Nuttall Consulting in its final report to the AER on its assessment of the revised regulatory proposals has provided an additional explanation of the methodology used to derive its weighted probability assessment. This approach sets out the weightings for each parameter for its project reviews and the basis of the overall probability weighting recommended to be applied to each DNSP's forecast reinforcement capex.

To estimate the reinforcement capital expenditure that would be consistent with forecast capital expenditure that reasonably reflects the capital expenditure criteria, the AER agrees in principle that the weighted average probability assessment recommended by Nuttall Consulting is a credible and valid methodology. However, the AER acknowledges that this methodology requires further testing in order to be used to reliably determine what the total forecast reinforcement capital expenditure that would reasonably reflect the capital expenditure criteria over the forthcoming regulatory control period. For these reasons the AER has decided not to apply this methodology to determine the total reinforcement capex in this final decision.

There are a number of difficulties in assessing and determining an appropriate level of reinforcement capital expenditure given the number of individual projects that make up the reinforcement forecast at both the subtransmission and distribution levels. Significantly, there is also an information asymmetry between the DNSPs and the AER in determining a reasonable reinforcement expenditure forecast. Given these difficulties, consideration might be given by policymakers to the introduction of an incentive scheme to reward/penalise businesses for accurate/inaccurate forecasting, possibly modelled on the scheme which has been introduced by the United Kingdom regulator Ofgem.

[25] ibid., p.24.
[26] Ibid., p.24.

P.2.5.2 CitiPower

The AER considered in its draft decision that CitiPower had not adequately demonstrated that its proposed forecast in reinforcement expenditure was a prudent and efficient forecast consistent with the capex criteria. The AER considered that there was a low probability that the reinforcement expenditure, excluding CBD Security of Supply and Metro 2012, would be required as proposed by CitiPower in the forthcoming regulatory control period.

The following sections outline CitiPower's response to the key issues raised in the draft decision, Nuttall Consulting's assessment and the AER's considerations for the final decision on CitiPower's reinforcement capex.

Methodological issues

Planning criteria

CitiPower stated in its revised regulatory proposal that its internal planning criteria incorporates the same criteria as CitiPower's governance documents, which Nuttall Consulting concluded would be expected to deliver prudent and efficient outcomes.[27]

Nuttall Consulting considered that CitiPower's internal planning criteria were reasonable for internal planning purposes. However, although CitiPower's documentation explained that how its forecasts were derived, the AER considered that CitiPower had not demonstrated that they had provided forecasts that were prudent and efficient. CitiPower's argument was that because its overall governance processes were sound, every forecast produced must also be sound. In the draft decision the AER agreed with Nuttall Consulting that the internal planning criteria assumed by CitiPower did not adequately demonstrate how the economic benefits through the reduction in the energy at risk outweigh the cost of the projects forecast. CitiPower did not address this issue.

Load duration curve assumptions

In the draft decision, the AER agreed with Nuttall Consulting's concerns with key input assumptions used by CitiPower for its forecasts. Specifically, the AER considered that the average load profile from 2001–05 used by CitiPower may overstate risks and could result in projects being advanced by up to three years. These key methodological issues were further supported by its detailed project review.

CitiPower considered that its load profile from 2001-2005 would not result in a systematic upward bias in its estimate of prudent expenditure. CitiPower and Powercor engaged SKM to undertake analysis of the load duration curves used to calculate energy at risk. SKM considered that Nuttall Consulting's analysis is flawed because it places significant weight on the shape of the top one per cent of the summer load duration curves. SKM considered that this part of the curve has little impact on the energy at risk.[28]

Nuttall Consulting reviewed this analysis but considered that the results supported its view that project timing will be sensitive to load profile assumptions, as the results

[27] CitiPower, *Revised regulatory proposal*, p.268.
[28] CitiPower, *Revised regulatory proposal*, p.269.

show a variation of 1 year depending on the load profile assumed. Nuttall Consulting also considered that, for the economic analysis that is intrinsic in these calculations to be valid, it is important that the load profile assumption adopted by the network planner should reasonably reflect the most likely conditions in the future.[29]

The AER considers that under a probabilistic planning framework the load profile curve will impact on the timing of the forecast. The extent to which this impact is significant will depend on the specific circumstances. SKM has raised concerns that the significance of the top one per cent of the load duration curve may be overstated. Nuttall Consulting rightly notes that the load profile assumptions should reasonably reflect most likely conditions to face the network. In relation to CitiPower's proposed projects though, Nuttall Consulting has concluded that the differences in the assumptions would not be significant in the timing of augmentations. The AER therefore agrees with Nuttall Consulting that a low weighting be given to the load duration curve assumptions compared with other factors in the assessment of the prudency and efficiency of the reinforcement forecast.

Maximum demand forecasts

CitiPower stated that Nuttall Consulting's forecast of reinforcement capex does not consider forecast maximum demand and the zone substation maximum demand forecasts are consistent with NIEIR's system maximum demand forecast. Thus the maximum demand forecasts used to forecast reinforcement capex are not likely to result in a systematic bias in the estimate.[30]

The AER has undertaken a more detailed review of the zone substation maximum demand forecast at the zone substations that are driving the major reinforcement projects – refer to the growth forecasts in chapter 5 of this final decision for further discussion. The outcomes of this review have been taken into account in the detailed project assessment undertaken by the AER.

Project Review

In the draft decision the AER considered that based on the Nuttall Consulting assessment, the timing of the major projects did not appear to be economically justified, in terms of the benefits through the reduction in energy at risk. Nuttall Consulting considered that a more thorough economic evaluation may determine that the deferral of a project or a lower cost infrastructure alternative is the most efficient option.

The following outlines CitiPower's response to the key issues raised in relation to the material projects, Nuttall Consulting's and the AER's assessment of the revised regulatory proposal for the material reinforcement projects.

CBD Security of Supply and Metro 2012

In the draft decision, the AER agreed with Nuttall Consulting that CitiPower had not adequately demonstrated the basis of the proposed additional expenditure included in

[29] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 54-56.
[30] CitiPower, *Revised regulatory proposal*, p.272.

the forecasts. The AER therefore allowed for the costs included in the original regulatory test with adjustments for cost escalations.

In annexure 9.1 of its revised regulatory proposal, CitiPower provided further detail in relation to costs for the CBD security of supply and Metro 2012 projects. CitiPower considered that the cost forecasts in the revised regulatory proposal are within a reasonable range of the values used in the regulatory test, having regard to the areas of uncertainty highlighted in the SKM report.[31] CitiPower also submitted that while costs at the time of the regulatory test are slightly below the actual costs, the regulatory test is likely to have significantly understated the benefits of both projects.[32]

Nuttall Consulting reviewed the additional information provided by Citipower and considered the matters raised in CitiPower's revised regulatory proposal. Overall, Nuttall Consulting considered that the significant cost increases above the approved costs are mostly likely warranted and was satisfied that they were a reasonable estimate.[33]

The AER considers that based on the additional information provided on the costs for the Metro 2012 project and the review undertaken by Nuttall Consulting that the revised costs for the CBD Security of Supply and Metro 2012 projects are within a reasonable range of the original projects estimates, which have been previously approved. The AER is therefore satisfied that the proposed $92 million ($2010) for these two projects is consistent with a total forecast capital expenditure that reasonably reflects the capital expenditure criteria.

11 kV feeder works

The AER, in the draft decision, agreed with Nuttall Consulting's assessment that the energy at risk does not support the cost of the project as proposed by CitiPower.

CitiPower submitted that its further information in the revised regulatory proposal demonstrates that the energy at risk justifies the works and that there are no other low cost alternatives. It considered that the feeder works were considered as part of the ESCV's review, however, they were most efficiently undertaken with ongoing load related augmentations.[34]

Nuttall Consulting undertook a detailed review of CitiPower's further information and separately assessed the proposed works that are security related and those works that are capacity related. For the security related works Nuttall Consulting considered that CitiPower had adequately demonstrated that the range of options considered were reasonable and comprehensive. Taking this into account, Nuttall Consulting considered that this assessment of the security related works had a high probability of proceeding as forecast in the forthcoming regulatory control period.[35]

The AER has considered the further material provided by CitiPower as well as Nuttall Consulting's assessment on the security related works. The AER considers that

31 CitiPower, *Revised regulatory proposal - Annexure 9.1*, p. 568.
32 CitiPower, *Revised regulatory proposal - Annexure 9.1*, p. 568.
33 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 57.
34 CitiPower, *Revised regulatory proposal*, p.275.
35 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 56-59.

CitiPower has demonstrated that it has considered all reasonable options. The AER also considers that these works are required to meet CitiPower's Melbourne CBD Security of Supply Project Plan. Therefore, based on this assessment of the security related 11 kV feeder works, the AER considers the projects are prudent and efficient expenditure, consistent with the capex criteria having regard to the capex factors set out in section P.2.1.

Regarding the capacity related projects, Nuttall Consulting noted that the combined expected value of unserved energy at zone substations JA, MP, WA and FR is $379,619 in 2015. In each instance, the capital cost does not justify the avoidance of this energy at risk for these projects, which is due to commence in 2011. Therefore, Nuttall Consulting considered that the capacity related works have not been justified and could be deferred by 2 to 3 years.[36]

The AER has assessed the material provided by CitiPower regarding the capacity related projects. The AER agrees with Nuttall Consulting that the energy at risk does not justify the capacity related 11kV feeder works to commence in 2011. The AER therefore considers that this project is not justified as being prudent and efficient expenditure. The AER considers that based on the energy at risk used to justify the timing of this project, that capacity related feeder works are not justified to be operating until 2017. Therefore, based on the expenditure profile proposed by CitiPower, the AER considers that the commencement of these works can be prudently deferred for two years from 2011 to 2013. This assessment is consistent with a total forecast capex that reasonably reflects the capex criteria, with the AER approach to assessing reinforcement, and has had regard to the capex factors outlined in section P.2.1.

3rd transformer at BQ

In the draft decision the AER agreed with Nuttall Consulting's assessment that there was a low probability that the proposed 3rd transformer at BQ zone substation would be required as forecast by CitiPower. The assessment found that there may be lower cost alternatives found with further analysis.

In its revised regulatory proposal, CitiPower submitted that the further information it provided demonstrates that the energy at risk and more detailed information on the economic analyses justifies the project going ahead as forecast in the forthcoming regulatory control period. CitiPower provided a network planning proposal for this project in attachment 161 of its revised regulatory proposal.[37]

Nuttall Consulting considered that this project is reliant on the 11 kV feeder capacity related works which it considers has a low probability of proceeding. Nuttall Consulting also considered that CitiPower had not fully considered all the feasible options.[38]

The AER notes that the energy at risk is based on the connection at the CUB redevelopment. However the AER in its draft decision did not consider that CitiPower

36 ibid., p.53.

37 CitiPower, *Revised regulatory proposal*, p.278.

38 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 60-62.

had provided sufficient information to suggest the connection would proceed in the time forecast by CitiPower, which was accepted by CitiPower in its revised regulatory proposal.

The AER also considers that energy at risk is reliant on the transfer of load to BQ through the 11kV feeder capacity works. However, based on the AER's view that the capacity related works could be deferred for two years, the AER considers that this project should also be deferred by two years.

The AER agrees with the Nuttall Consulting assessment that this project can be deferred for two years, from 2012 to 2014, as the energy at risk does not justify this project proceeding as forecast by CitiPower. This assessment is consistent with a total forecast capex that reasonably reflects the capex criteria, with the AER's approach to assessing reinforcement, and has had regard to the capex factors outlined in section P.2.1.

Docks area zone substation upgrade

In the draft decision the AER agreed with Nuttall Consulting's assessment of a low probability for this project that the proposed project should be deferred. The AER also considered that there may be lower cost options that may be justified through more detailed analysis.

CitiPower submitted that the further information it provided, in attachment 62 to its revised regulatory proposal, justifies the proposed timing of the project. Regarding lower cost options, CitiPower submitted that alternative options such as establishing a second zone substation would be a significantly higher cost, including land purchases, sub-transmission lines under the Yarra, and 11 kV feeders.[39]

Nuttall Consulting in its assessment of this project considered that the energy at risk only marginally supported the project around the end of the period. It considered that a permanent load transfer away of 7 MVA as proposed by CitiPower has not been included in the energy at risk calculations. It also considered the energy at risk could be offset for a period by cogeneration or demand side initiatives.[40]

The AER notes that ACIL Tasman in its review of maximum demand forecasts for selected zone substations, found issues with the maximum demand forecasts at this zone substation, where forecast growth rates had not been adequately justified. ACIL Tasman recommended a 6.7 per cent reduction over the forecast regulatory period. This recommendation has been accepted by the AER – refer to the growth forecasts chapter.

The AER considers that the energy at risk does not justify this project proceeding as forecast by CitiPower for the following reasons. The transfer away of 7 MVA has not been accounted for in the energy at risk calculation. This is further supported by a 6.7 per cent reduction in maximum demand forecasts at the Docks Area zone substation. When the maximum demand forecast is revised downwards and is included in the energy at risk calculation, the AER considers this project is not required until 2017.

39 CitiPower, *Revised regulatory proposal*, p.278.
40 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 62-64.

Based on CitiPower's estimate for the profile of expenditure for this project, the project commencement should be deferred for two years from 2012 to 2014. The AER considers that deferring this project from 2012 to 2014 is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the AER approach to assessing reinforcement, and has had regard to the capex factors outlined in section P.2.1.

AER conclusions

The AER has assessed CitiPower's revised regulatory proposal for reinforcement capex and the additional material proposed to support the economic justification for the major projects forecast for the forthcoming regulatory control period.

The AER has also reviewed the maximum demand forecasts that are driving the key augmentation projects. Based on this review the AER considers that the maximum demand forecasts proposed by CitiPower used to generate its energy at risk calculations are reasonable, with the exception of forecast maximum demand at the Docks area and Celestial Avenue zone substations. The revised forecast maximum demand at these two zone substations has been taken into account in the reinforcement capex assessment.

Based on the assessment of major augmentation projects and methodologies used to determine CitiPower's reinforcement forecasts across the subtransmission and distribution categories, the AER considers there are a number of issues with the economic justification for the timing of the projects and with the economic options considered for CitiPower's proposed reinforcement capex. The AER considers that the proposed forecasts do not adequately take account of the further detailed analysis and refinement of projects that results in the actual projects that are required and undertaken in the forecast period. This is consistent with previous regulatory control periods where actual expenditure has been considerably less than what DNSPs have originally forecast.

Based on this assessment, the AER is not satisfied that CitiPower has justified that its forecast of reinforcement expenditure reasonably reflect the efficient cost of achieving the capex objectives, specifically to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

This assessment is consistent with the capex criteria and the AER approach to assessing reinforcement outlined section in section P.2.1. In doing so this assessment has also had particular regard to capex factor (1), taking into account the information in CitiPower's regulatory proposal; capex factor (3), whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting; capex factor (4) in assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP; and capex factor (10), where the AER has taken into account the extent to which CitiPower has considered and made provision for efficient, non-network alternatives.

Regarding the CBD security of supply and Metro 2012 projects, the AER considers that based on its assessment of the additional material provided by CitiPower, that the proposed forecast expenditure for these projects is reasonable.

In determining an alternative forecast of reinforcement capex the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast of reinforcement capex. However, the AER also acknowledges that based on the loading of the CitiPower network, that an increase in reinforcement capex is required in the forthcoming regulatory control period.

The AER has considered Nuttall Consulting's detailed review of methodologies used to derive the reinforcement expenditure forecasts and the sample of detailed project reviews undertaken. The AER considers this methodological and project review has provided a reasonable assessment of the issues that exist across each category of CitiPower's reinforcement forecast. The AER has therefore taken into account Nuttall Consulting's findings from its review to determine the prudency and efficiency of the major augmentation projects reviewed. However, as described above, the AER considers that Nuttall Consulting's weighted average probability assessment requires further testing before it is adopted for general use as an appropriate methodology to determine a reasonable forecast of reinforcement capex within the requirements of the rules.

Based on its assessment of CitiPower's revised regulatory proposal for reinforcement, the AER considers that an allowance for reinforcement expenditure of $212.7 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. The AER also considers that the level of expenditure will allow CitiPower to meet the needs and other obligations as outlined in the NER and NEL. In its consideration the AER has had regard to the revenue and pricing principles.

This section has assessed CitiPower's proposed allowance for reinforcement expenditure which is one component of CitiPower's proposed total forecast capital expenditure. The AER considers that the level of expenditure determined in this appendix is consistent with the requirement in clause 6.5.7(c) of the NER that the total forecast capital expenditure reasonably reflects the capital expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capital expenditure. That constituent decision, which should be read together with this appendix, is discussed in the capex chapter 8.

P.2.5.3 Powercor

Based on its review and the assessment undertaken by Nuttall Consulting the AER in its draft decision considered that Powercor had not adequately demonstrated that its proposed increase in reinforcement expenditure was a prudent and efficient forecast consistent with the capex criteria. It considered that a reasonable estimate would be more in line with historical trend.

In its draft decision the AER agreed with Nuttall Consulting's methodological and detailed projects reviews and the issues found with Powercor's proposed reinforcement expenditure. The AER agreed with Nuttall Consulting that there was a moderate probability of the total forecast reinforcement expenditure proposed by Powercor being required in the forthcoming regulatory control period.

The following sections outline the Powercor's response to the key issues raised in the draft decision, Nuttall Consulting's assessment and the AER's considerations for the final decision on Powercor's reinforcement capex.

Methodological Issues

Internal planning criteria

The AER in its draft decision considered that the internal planning criteria assumed by Powercor, did not demonstrate how the economic benefits through the reduction in the energy at risk outweigh the cost of the projects forecast.

Powercor stated in its revised regulatory proposal that its internal planning criteria incorporate the same criteria as Powercor's governance documents. Powercor considered that the rigour of the analysis applied by Powercor Australia in its forecasting and its governance processes is the same. Any changes in scope and timing are the result of new information rather than more detailed analyses being conducted.[41]

Nuttall Consulting considered that Powercor's internal planning criteria were reasonable for internal planning purposes. However, although Powercor's documentation explained that how its forecasts were derived, the AER considered that Powercor had not demonstrated that they had provided forecasts that were prudent and efficient. Powercor's argument was that because its overall governance processes were sound, every forecast produced must also be sound. In the draft decision the AER agreed with Nuttall Consulting that the internal planning criteria assumed by Powercor did not adequately demonstrate how the economic benefits through the reduction in the energy at risk outweigh the cost of the projects forecast. Powercor did not address this issue.

Load profile

Nuttall Consulting considered, in its assessment for the draft decision, that the load profile from 2009 used by Powercor may overstate risks due to the number of extended periods of high temperature captured in the 2009 period. By selecting a single year as the basis of the forecast and that year being a year with abnormally high temperatures, Nuttall Consulting considered that Powercor was applying data that are inconsistent with a 50 per cent Probability of Exceedance (PoE) criterion, which is the norm for studies under Powercor's own planning framework. Nuttall Consulting considered that applying a load profile that is more representative of 50 per cent PoE conditions may result in projects being deferred by up to three years.

In its revised regulatory proposal, Powercor stated that it considered that its use of a load profile from 2009 will not result in a systematic upward bias in its estimate of prudent and efficient reinforcement capex. CitiPower and Powercor engaged SKM to undertake analysis of the load duration curves used to calculate energy at risk. Powercor considered that Nuttall Consulting's analysis is flawed because it places significant weight on the shape of the top one per cent of the summer load duration curves. SKM considered in its report this part of the curve has little impact on the energy at risk.[42]

Nuttall Consulting reviewed this analysis but considered that the results supported its view that project timing will be sensitive to load profile assumptions, as the results

41 Powercor, *Revised regulatory proposal*, p.269.
42 Powercor, *Revised regulatory proposal*, p.269.

show a variation of 1 year depending on the load profile assumed. Nuttall Consulting also considered that, for the economic analysis that is intrinsic in these calculations to be valid, it is important that the load profile assumption adopted by the network planner should reasonably reflect the most likely conditions in the future.[43]

The AER considers that under a probabilistic planning framework the load profile curve will impact on the timing of the forecast. The extent to which this impact is significant will depend on the specific circumstances. SKM has raised concern that the significance of the top one per cent of the load duration curve may be overstated. Nuttall Consulting rightly notes that the load profile assumptions should reasonably reflect most likely conditions to face the network. However, in relation to Powercor's proposed projects, Nuttall Consulting has concluded that the differences in the assumptions would not have a significant impact on the timing of augmentations. The AER therefore agrees with Nuttall Consulting that a low weighting be given to the load duration curve assumptions compared with other factors in the assessment of the prudency and efficiency of the reinforcement forecast.

Project Review

Eaglehawk augmentation

In the draft decision the AER agreed with Nuttall Consulting's assessment that the Eaglehawk augmentation was economically justified and alternative options have been adequately considered, and therefore had a moderate to high probability of proceeding. In its revised regulatory proposal, Powercor considered that the load profile assumed is reasonable and therefore the project should be given a 100 per cent probability of proceeding.[44]

Nuttall Consulting considered that this project was justified. However, based on issues related to over forecasting, it considered that this project has a 90 per cent probability of proceeding as forecast.[45]

The AER considered the information provided by Powercor. It has also considered the assessment undertaken by Nuttall Consulting and the concerns of over forecasting. The AER also reviewed the maximum demand forecasts at the Eaglehawk zone substation and found them to be reasonable. Based on this assessment, the AER is satisfied that this project is reasonable as the energy at risk justifies the timing of this project and the alternative options have been adequately considered. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

Gisborne zone substation

The AER in its draft decision agreed with Nuttall Consulting's assessment that the planned augmentation works did not economically justify the proposed timing of the project.

In its revised regulatory proposal, Powercor provided further detailed justification of the energy at risk and consideration of alternative options for the proposed zone

[43] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.131.
[44] Powercor, *Revised regulatory proposal*, p.263.
[45] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p.132.

substation at Gisborne in attachment 161. It stated that this project has been through Powercor's internal governance process and no lower cost options were identified.[46]

Nuttall Consulting assessed the additional information provided by Powercor. Nuttall Consulting noted that the VCR was increased significantly between the initial and revised regulatory proposals. This resulted in a significant change in the justification for the project. The AER queried this with Powercor. Powercor stated in its response that there was an error in their original calculation of VCR, which was based on customer numbers rather than energy usage.[47] The AER agrees that the revised calculation of $45,353/MWh is reasonable, given that it is based on energy usage, and is still below the VCR average of $55,000 per/MWh.

Nuttall Consulting also had concerns with the options analysis undertaken by Powercor and that there is still potential for staging of the project. It considered that part of the project could be funded through the reliability incentive scheme.[48]

The AER has reviewed the additional information provided by Powercor in its revised regulatory proposal. The AER has taken into account the findings from Nuttall Consulting's detailed investigation of this project and has taken into account the capex criteria. The AER also reviewed the maximum demand forecasts driving the need for this augmentation and considers it to be reasonable. The AER also considers that due to the revised VCR rate that the energy at risk is sufficient to justify the timing of this project. The AER therefore considers that it is prudent for Powercor to undertake this project as forecast in the forthcoming regulatory control period. This assessment is consistent with the AER approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

Augmentation of Charlton to Bendigo sub–transmission line

In the draft decision the AER agreed with Nuttall Consulting that there was a moderate probability of this project being required as proposed by Powercor.

In its revised regulatory proposal Powercor considered that its maximum demand forecasts are conservative and it is not appropriate to assume a deferral of the project on this basis. Powercor also stated that further detailed information been provided to justify its view that no other lower cost options are possible. Further, that the first stages of this upgrade have been approved through Powercor's governance process and no lower costs were identified.[49]

Nuttall Consulting's assessment of this project found issues with the reasonableness of the options analysis undertaken by Powercor to justify the project. It considered that there are a number of potential options that have not been fully considered to address the supply limitations at Charlton. It also considered that there is a reasonable possibility that a lower cost option may be the preferred solution.[50]

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46 Powercor, *Revised regulatory proposal*, p.264.

47 Powercor, Response to information requested 3 September 2010, 9 September 2010.

48 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 131-133.

49 Powercor, *Revised regulatory proposal*, p.264.

50 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.133-135.

The AER has reviewed the additional information provided by Powercor in its revised regulatory proposal. The AER agrees with Nuttall Consulting that it is possible that a lower cost option could be found and that some stages of this project could potentially be deferred. However, the AER considers that as some form of augmentation is required and that the proposed project may be found to be the most economic option, the AER consider the forecast expenditure for this project to be reasonable. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1.

Geelong East transformer

In the draft decision the AER agreed with Nuttall Consulting's recommendation that there is a moderate probability of this project being required as forecast. This being based on the assessment that the energy at risk calculations suggest the timing is justified, however this does not appear to account for load transfers to other substations or feeders.

In its revised regulatory proposal Powercor argued that the value of energy at risk justifies this project. Powercor also considered that load duration curves used are reasonable and therefore it is not appropriate to assume a deferral of this project. Further, Powercor prepared an additional energy at risk calculation, based on a composite load duration curve, using data from 2006 to 2009 to produce an average load duration curve.[51]

Based on its further assessment of this project, Nuttall Consulting had a number of concerns with this project, being:

- the energy at risk is borderline in terms of justifying this project as being required in 2016.
- the energy at risk is driven by growth in demand during winter, which has not been justified.[52]

The AER considers that the increase in winter maximum demand has not been adequately justified by Powercor and that it is not consistent with the growth in summer maximum demand. Based on its assessment of the additional information provided by Powercor, the AER considers that this project has not been justified as prudent and efficient expenditure as the energy at risk for this project does not adequately justify the timing of this project as forecast by Powercor. This being that the energy at risk is driven by growth in winter demand that has not been justified as reasonable or consistent with the historical trend. The AER therefore agrees with Nuttall Consulting that it is prudent to adjust the timing of this project by deferring its commencement from 2014 to 2016. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1

Geelong sub–transmission lines upgrade

51 Powercor, *Revised regulatory proposal*, p.95.
52 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.136-138.

In the draft decision, the AER agreed with Nuttall Consulting that this project has a moderate to high probability of being required. This was because the energy at risk appeared to justify the timing. However, Powercor had not demonstrated that this was the least cost option.

In its revised regulatory proposal Powercor considered that as its load duration curve used in determining the energy at risk for this project is reasonable. It therefore considered that this project should be assigned 100 per cent chance of proceeding.[53]

Nuttall Consulting considered that although Powercor's economic justification for this project was reasonable, it retained the view that due to issues of over forecasting, that assigning a 90 per cent probability for this project was reasonable.

The AER has reviewed the additional material provided for this project and agrees with Nuttall Consulting's assessment that this project has been justified as reasonable by Powercor though there are issues with over forecasting that may result in some deferment in the completion of this project. However, based on its overall assessment the AER is satisfied that this project represents prudent and efficient expenditure consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1.

Cobram East - Numurkah 66 kV line upgrade

In the draft decision the AER accepted Nuttall Consulting's assessment that this projects has a moderate to high probability of being required. However, Powercor had not clearly demonstrated that the energy at risk is sufficient to justify the proposed project.

Powercor in its revised regulatory proposal considered that energy at risk for this project does justify it proceeding in the next period. Powercor also argued that the load curve has no bearing on the energy at risk for this project as it is a radial line. Powercor provided further detail on the justification for this project in attachment 161 to the revised regulatory proposal.[54]

Based on its assessment of this project, Nuttall Consulting maintained the view that this project has a moderate to high probability of proceeding as forecast by Powercor. In addition to general concerns of historical over forecasting of reinforcement needs, this assessment found:

- the possibility that the risks can be prudently and efficiently managed for another 1 to 2 years
- the project will be partly funded through the reliability incentive scheme.[55]

The AER considers that based on the information provided by Powercor that the energy at risk is sufficient to justify this project proceeding. However the AER agrees with Nuttall Consulting that despite the high energy at risk on this subtransmission

53 Powercor, *Revised regulatory proposal*, p.265.
54 Powercor, *Revised regulatory proposal*, p.266.
55 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p.127.

line that Powercor has been able to manage this risk, which has not been explained in its documentation. In spite of these concerns, as the energy at risk does justify an augmentation, the AER considers the project is justified to occur as forecast by Powercor. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1.

AER conclusion

The AER has assessed Powercor's revised regulatory proposal for reinforcement capex and the additional material proposed to support the economic justification for the projects reviewed by Nuttall Consulting and other material projects forecast for the forthcoming regulatory control period.

The AER has also reviewed the maximum demand forecasts that are driving Powercor's key augmentation projects. Based on this review the AER considers that the proposed maximum demand forecasts by Powercor's used to generate its energy at risk calculations are reasonable.

Based on the assessment of major augmentation projects and methodologies used by Powercor to determine its reinforcement forecasts across the subtransmission and distribution categories, the AER considers there are a number of issues with the economic justification for the timing of the projects and with the economic options considered for Powercor's proposed reinforcement capex. The AER considers that the proposed forecasts based on a bottom up build of all projects do not adequately take account of the further detailed analysis and refinement of projects that results in the actual projects that are required and undertaken in the forecast period. This is consistent with previous regulatory control periods where actual expenditure has been considerably less than what DNSPs have originally forecast.

Based on this assessment, the AER is not satisfied that Powercor has justified that its forecast of reinforcement expenditure reasonably reflects the efficient cost of achieving the capex objectives, specifically to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

This assessment is consistent with the capex criteria and the AER approach to assessing reinforcement outlined section in section P.2.1. In doing so this assessment has also had regard to capex factor (1), in taking into account the information in Powercor's regulatory proposal; capex factor (3), whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting; capex factor (4) in assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP; and capex factor (10), where the AER has taken into account the extent to which Powercor has considered and made provision for efficient, non-network alternatives.

In determining an alternative forecast of reinforcement capex the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast of reinforcement capex. However the AER also acknowledges that based on it assessment of the load on Powercor's network that an increase in reinforcement capex is required in the forthcoming regulatory control period.

The AER has considered Nuttall Consulting's detailed review of methodologies used to derive the reinforcement expenditure forecasts and the sample of detailed project reviews undertaken. The AER considers this methodological and project review has provided a reasonable assessment of the issues that exist across each category of Powercor's reinforcement forecast. The AER further considers that Nuttall Consulting has adequately assessed the additional information provided in Powercor's revised regulatory proposal and has factored this additional information into its weighted probability assessment. The AER has therefore taken into account Nuttall Consulting's findings from its review to determine the prudency and efficiency of the major augmentation projects reviewed. However, as described above, the AER considers that Nuttall Consulting's weighted average probability assessment requires further testing to be used as an appropriate methodology to determine a reasonable forecast of reinforcement capex within the requirements of the rules.

Based on its assessment of Powercor's revised regulatory proposal for reinforcement, the AER considers that an allowance for reinforcement expenditure of $230.4 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. The AER also considers that the level of expenditure will allow Powercor to meet the needs and other obligations as outlined in the NER and NEL. In its consideration the AER has had regards to the revenue and pricing principles.

This appendix has assessed the proposed allowance for reinforcement expenditure which is one component of Powercor's proposed total forecast capital expenditure. The AER considers that the level of expenditure determined in this appendix is consistent with the requirement in clause 6.5.7(c) of the NER that the total forecast capital expenditure reasonably reflects the capital expenditure criteria.

This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capital expenditure. That constituent decision, which should be read together with this appendix, is discussed in the capex chapter.

P.2.5.4 JEN

The AER in its draft decision agreed with Nuttall Consulting's recommendation that JEN had not adequately demonstrated that its proposed increase in reinforcement expenditure was reasonable. The AER accepted Nuttall Consulting's recommendation that there is a moderate probability that the reinforcement expenditure would be required as proposed by JEN.

The following sections outline JEN' response to the key issues raised in the draft decision, Nuttall Consulting's assessment and the AER's considerations for the final decision.

Methodological issues

In the draft decision the AER agreed with Nuttall Consulting's concerns that it was unreasonable for JEN to use a load profile based upon demand in 1999–2000, as it would overstate energy at risk and increase the level of proposed reinforcement capex.

JEN in its revised regulatory proposal noted that it had adjusted its load profile assumptions and adopted a 2007–08 load profile. JEN considered that 2007–08 reasonably reflects a 50 per cent PoE summer which forms the basis of JEN's planning methodology.[56]

Nuttall Consulting accepted that JEN's revised load profile should improve the accuracy of energy at risk forecasts. Nonetheless, it still considered that the revised load duration curve may still materially overstate the energy at risk, particularly in the latter half of the forthcoming regulatory control period. Nuttall Consulting, in its assessment, has taken into account JEN's revised load duration curves.[57]

The AER considers that the load profile will have an impact on the timing of the forecast. However, the AER also agrees with Nuttall Consulting that a low weighting be given to the load duration curve assumptions in the assessment of the prudency and efficiency of JEN's reinforcement forecast.

Project review

Preston/ East Preston conversion

In the draft decision the AER agreed with Nuttall Consulting's assessment that this project had a low to moderate probability of being required as forecast by JEN. It considered that further analysis will result in a more optimal timing and likely deferral of some elements.

In its revised regulatory proposal JEN considered that the additional information provided in its strategy paper justifies the project going ahead as planned. JEN also noted that a number of early stages of this project have already been completed.[58] JEN also provided additional information on the cost estimates for this project.[59]

Nuttall Consulting assessed the cost estimates provided by JEN, noting that it has a number of scope differences to its cost estimate, which Nuttall Consulting has accepted as reasonable. However Nuttall Consulting maintained the view that the key driver of this project is aged based replacement without adequate regard to the condition of the asset. Nuttall Consulting also considered that JEN had not sufficiently considered options to address feeder overload issues. Nuttall Consulting has reviewed the asset replacement planning information provided by JEN and considers that the condition of the asset would allow up to a two year deferment.[60]

The AER considers that the key driver for this project appears to be age related replacement without adequate regard to the condition of the asset. The AER agrees with the Nuttall Consulting assessment that due to the condition of the asset it does not require replacement in the timing as forecast. The AER also considers that JEN has not sufficiently assessed options to address feeder overload issues. Based on its assessment the AER considers that the expenditure forecast for this project can be prudently deferred by two years from 2011 to 2013. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1.

[56] JEN, *Revised regulatory proposal*, p.152.
[57] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 93.
[58] JEN, *Revised regulatory proposal*, p.149.
[59] JEN, *Costing Analysis and Comments on Tullamarine and East Preston/Preston Conversion projects*, August 2010.
[60] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 94-95.

Pascoe Vale transformer upgrade

In the draft decision the AER agreed with the Nuttall Consulting assessment that there was a moderate probability of this project being required. This was based on the conclusion that the energy at risk was not sufficient to justify this project and there was not sufficient evidence to suggest that alternatives have been fully considered.

In its revised regulatory proposal JEN developed a business case for the project and provided detailed calculations of energy at risk, timing and an assessment of alternative options.[61]

Nuttall Consulting considered in its review that the expected unserved energy is not reasonable to justify the timing of the project. Nuttall Consulting considered this was due to JEN using a conservative rating to justify the augmentation. Nuttall Consulting considered that it is reasonable to use a cyclic rating of at least 110 per cent of name plate rating, which results in the value of expected unserved energy of $137k in 2012. However, as the cost to augment the substation is greater than the expected value of unserved energy, this does not justify the project proceeding as forecast by JEN.[62]

Nuttall Consulting also considered that JEN had not justified that this project is the most economic option in its business case and it identified other low cost options that could delay the need for the major substation refurbishment. Based on its assessment Nuttall Consulting retained the view that this project is not justified as prudent and efficient.[63]

The AER has reviewed the additional material provided JEN. The AER considers that that the energy at risk does not justify the timing of the project as forecast by JEN. The AER also considers that, based on Nuttall Consulting's assessment, JEN has not adequately considered that there may be lower cost options to address the energy at risk at this substation. On this basis, the AER considers that deferring the commencement of this project from 2011 to 2013 is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1.

Tullamarine new zone substation

In the draft decision the AER agreed with Nuttall Consulting that this project had a moderate probability of being required. This was based on the assessment that there was not a clear demonstration that energy at risk is sufficient to justify the timing of the project.

JEN in its revised regulatory proposal retained the view that this project will proceed as forecast in its initial proposal. In appendix 8.1 of its revised regulatory proposal JEN provided an additional business case, including detailed calculation of the energy at risk, timing and options analysis.[64]

61 JEN, *Revised regulatory proposal*, p.150.
62 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.94-95.
63 ibid., pp. 94-95.
64 JEN, *Revised regulatory proposal*, p.150.

Nuttall Consulting considered that based on the revised information Nuttall Consulting considered that the energy at risk may justify the timing of the project, however a large proportion of this energy at risk is due to feeder utilisation. Based on this Nuttall Consulting considered that the project may be deferred by one to two years given its assessment of the assumptions used by JEN to calculate energy at risk. It also considered given this high utilisation that that an alternative option could be found to address the feeder utilisation. Nuttall Consulting also considered that the proposed HV feeder works will result in improvements in reliability and therefore should not be funded from regulated revenue.[65]

The AER considers that the energy at risk does not reasonably justify this project proceeding in the timing forecast by JEN. It also considers that there is potential that an alternative option could be found to address the high feeder utilisation. It also agrees with the issues identified by Nuttall Consulting that if funded on the timing proposed by JEN this project could result in an increase in reliability, contrary to the incentives provided by the Service Target Performance Incentive Scheme. The AER considers that based on this assessment, it is reasonable to defer this project by two years from 2011 to 2013. The AER considers that deferring this project from 2011 to 2013 is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1.

TTS-CN-CS-TTS 66kv line

In the draft decision the AER agreed with Nuttall Consulting's assessment that this project had a high probability of being required. This was based on the assessment that the cost of energy at risk appears to justify the project and the alternative options have been reasonably considered.

In its revised regulatory proposal, JEN stated that it does not understand why a probability of 90 per cent is given for a project that is considered justified proceeding in the next regulatory control period.[66]

Nuttall Consulting acknowledged that it is satisfied that the energy at risk should be sufficient to justify the project and therefore, can be assigned a high probability of proceeding. However, Nuttall Consulting considers that based on its high level findings of consistent over forecasting, a reduced probability for even the very high probability projects appears reasonable.[67]

The AER considers that based on the additional information provided that this project is justified to proceed as forecast by JEN. The AER notes the concerns raised by Nuttall Consulting of over forecasting. However, given that the energy at risk justifies this project proceeding as forecast by JEN and that JEN has reasonably considered alternative options, the AER considers this project is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the

65 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 98-100.
66 JEN, *Revised regulatory proposal*, p.150.
67 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 98-100.

AER's approach to assessing reinforcement. The AER has had regard to the capex factors outlined in section P.2.1.

KTS-MAT-AW-PV-KTS 66kv loop

In the draft decision the AER agreed with Nuttall Consulting's assessment that this project had a low probability of being required, based on the assessment that the cost of energy at risk indicates the project should be deferred by 1 to 2 years.

JEN, in response to Nuttall Consulting's criticisms, developed a business case for this project, providing a detailed calculation of load at risk, timing and options analysis in appendix 8.12.[68]

Nuttall Consulting, in its assessment, found that the values of expected unserved energy are materially different to those in the initial regulatory proposal with the difference due to JEN including the value of energy associated with pre-contingent load shedding. Nuttall Consulting considered that it is reasonable to includes these values in the energy at risk calculations, and therefore consider the economic timing to be reasonable. Nuttall Consulting also raised some concerns with the calculation of unserved energy associated with the pre-contingent load shedding. However, based on the low materiality of this element of the project, it accepted JEN's criteria and considered that the revised value of unserved energy justifies the proposed staged project, as recommended by JEN.[69]

The AER considers that, based on the additional information provided, this project, as forecast is acceptable as the energy at risk justifies the timing of this project. The AER also notes the concerns of Nuttall Consulting that due to past issues of over forecasting that there is a possibility this project may not proceed as forecast. The AER has also assessed the maximum demand forecasts driving this augmentation and has considered them to be reasonable. Therefore taking this information into account the AER has concluded that this project is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the AER's approach to assessing reinforcement. The AER has had regard to the capex factors outlined in section P.2.1

Distribution transformer program

The AER in the draft decision agreed with Nuttall Consulting's assessment that this project was not justified as prudent and efficient expenditure as it was unclear how the transformer replacement program would efficiently reduce failure rates.

JEN in its revised regulatory proposal asserted that this program is required in the forthcoming regulatory control period. JEN rejected the argument that the heavily utilised transformers cannot be targeted. JEN stated that it has taken on board the AER's comments and has extended the program over seven years rather than six years as proposed in the original proposal, effectively reducing the program expenditure by about 17 per cent in the forthcoming regulatory control period. JEN also provided

68 JEN, *Revised regulatory proposal*, p.151.
69 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 101-103.

additional supporting documentation in appendix 8.17 to its revised regulatory proposal.[70]

Nuttall Consulting considered that, based on its review of the additional information provided by JEN, the fundamental concerns with the methodology have not been addressed. This being that JEN has not justified how the program will effectively target transformers such that it will economically reduce the failure rate. Nuttall Consulting also considered that JEN is proposing a conservative utilisation rate for its planned replacement compared with United Energy and SP AusNet. Therefore, based on its assessment, Nuttall Consulting did not consider the program to be prudent and efficient consistent with the capex criteria. Nuttall Consulting considered that there appears to be evidence that a planned replacement may be required, but it did not consider that JEN had addressed the scale of increases. Nuttall Consulting considered it is reasonable to assume that transformers operating at over 140 per cent of rating may be planned for replacement rather than at 100 per cent of rating as proposed by JEN. Nuttall Consulting also considered that this program should be spread over a 10 year period as there should be a trending downwards of risk rather than a step down. Based on this assessment, Nuttall Consulting considered that historical expenditure for this project should be allowed, plus a 70 per cent reduction in the new program. This is based on using a higher utilisation criterion for determining replacement and spreading the program over a longer period.[71]

The AER considers that based on its assessment and the advice of Nuttall Consulting, that the additional information provided by JEN does not provide adequate justification that the program will efficiently reduce the failure rate of distribution transformers. It is common practice in the distribution industry to allow transformers to operate at levels above nameplate ratings for limited periods to address contingencies. Persistent, sustained operation at levels above 100 per cent of unit rating will ultimately shorten the life of a transformer. The adverse effects of overloading are not linear and will be more profound in the case of transformers with higher degrees of overloading. Nuttall Consulting considers the remaining life of transformers with a sustained loading greater than 140 per cent will be compromised to an extent sufficient to warrant replacement in the forthcoming regulatory control period. Transformers exposed to a lesser degree of overloading are less likely to fail in the forthcoming regulatory control period.

The AER does not consider that a prudent or efficient DNSP would prematurely replace a transformer even if its overall service life has been compromised by overloading unless condition based assessments, taking into account the degree of historical overloading, had indicated failure was imminent. A prudent operator will seek to manage this replacement strategy over more than one regulatory period.

The AER considers the JEN has taken into account the AER draft decision and has deferred some expenditure for this program in its revised regulatory proposal. However the AER agrees with Nuttall Consulting's assessment that it is reasonable to allow for historical expenditure for this program with some additional increase for replacement of transformers with a high utilisation. However the AER considers that the additional expenditure be reduced based on the higher utilisation criteria of 140

70 JEN, *Revised regulatory proposal*, p.152.
71 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 104-105.

per cent of rating rather than 100 per cent proposed by JEN as the higher rate will produce a program more in keeping with the equivalent programs of SP AusNet and United Energy. Based on a higher utilisation rate, the AER considers that 30 per cent of the proposed replacement program is required. The AER therefore considers that an allowance for this program of $17.9 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1.

Transfer of expenditure

JEN in its revised regulatory proposal retained the view that property purchases for zone substation augmentations should be categorised in the 'non-network-other' category because property purchase is related to the future requirement for the new zone substation, property purchase would need to be ahead of time, especially in the general build-up area that JEN serves.[72]

The AER considers that it is reasonable for JEN to purchase land in advance for future zone substations. However, the AER considers that land purchases form part of the proposed costs to undertake the augmentation works and are used to justify the economic timing in the energy at risk calculations and the economic option analysis as part of the justification of the project. Therefore the AER retains the view that the key driver for property purchases is reinforcement of the network, therefore the expenditure should be retained within the reinforcement capex category.

Consistent with this approach the AER has also transferred expenditure related to capacitor banks from the non-network other category to reinforcement as it considers augmentation to be the key driver of this expenditure.

AER conclusion

The AER has assessed JEN's revised regulatory proposal for reinforcement capex, other material projects and the additional material proposed to support the economic justification for the projects reviewed by Nuttall Consulting for the forthcoming regulatory control period.

The AER has taken into account the review undertaken by Nuttall Consulting and its key findings on the methodologies used to develop JEN's forecast and the detailed projects reviews undertaken. The AER has also reviewed the maximum demand forecasts that are driving JEN's key augmentation projects. Based on this review the AER considers that the proposed maximum demand forecasts by JEN's used to generate its energy at risk calculations are reasonable. Refer to the growth forecasts chapter for further detail of this assessment.

Based on the assessment of major augmentation projects and methodologies used to determine JEN's reinforcement forecasts across the subtransmission and distribution categories, the AER considers there are a number of issues with the economic justification for the timing of the projects and with the economic options considered for JEN's proposed reinforcement capex. Regarding the distribution transformer program, the AER agreed with the Nuttall Consulting that JEN has not demonstrated

72 JEN, Revised regulatory proposal, p.152.

that the program will efficiently reduce the failure rates of transformer and therefore realise the necessary benefits to justify the program.

The AER also considers that the proposed forecasts do not adequately take account of the further detailed analysis and refinement of projects that results in the actual projects that are required and undertaken in the forecast period. This is consistent with previous regulatory control periods where actual expenditure has been considerably less than DNSPs had originally forecast.

Based on this assessment the AER is not satisfied that JEN has justified that its forecast of reinforcement expenditure reasonably reflect the efficient cost of achieving the capex objectives, specifically to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

This assessment is consistent with the AER's approach to assessing reinforcement and the capex criteria. The AER has had regard to the capex factors outlined in section P.2.1. In doing so this assessment has also had regard to capex factor (1), in taking into account the information in JEN's regulatory proposal; capex factor (3), whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting; capex factor (4) in assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP; and capex factor (10), where the AER has taken into account the extent to which JEN has considered and made provision for efficient, non-network alternatives.

In determining an alternative forecast of reinforcement capex the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast of reinforcement capex. However, the AER also acknowledges that based on its assessment of the loading of JEN's network, that an increase in reinforcement capex is required in the forthcoming regulatory control period.

The AER has considered Nuttall Consulting's detailed review of methodologies used to derive the reinforcement expenditure forecasts and the sample of detailed project reviews undertaken. The AER considers this methodological and project review has provided a reasonable assessment of the issues that exist across each category of JEN's reinforcement forecast. The AER has therefore taken into account Nuttall Consulting's findings from its review to determine the prudency and efficiency of the major augmentation projects reviewed. However, as described above the AER considers that Nuttall Consulting's weighted average probability assessment requires further testing to be used as an appropriate methodology to determine a reasonable forecast of reinforcement capex within the requirements of the rules.

Based on its assessment of JEN's revised regulatory proposal for reinforcement, the AER considers that an allowance for reinforcement expenditure of $92.4 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this level of expenditure will allow JEN to meet the needs and other obligations as outlined in the NER and NEL. In its consideration the AER has had regard to the revenue and pricing principles.

This appendix has assessed the proposed allowance for reinforcement expenditure which is one component of JEN's proposed total forecast capital expenditure. The AER considers that the level of expenditure determined in this appendix is consistent with the requirement in clause 6.5.7(c) of the NER that the total forecast capital expenditure reasonably reflects the capital expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capital expenditure.

P.2.5.5 SP AusNet

The AER in its draft decision considered that based on its review and the detailed technical assessment undertaken by Nuttall Consulting, that SP AusNet had not adequately demonstrated that its proposed increase in reinforcement expenditure is reasonable. It considered that a reasonable estimate would be more in line with historical trend. The AER agreed with the Nuttall Consulting's weighted probability assessment and in the draft decision allowed for 53 per cent of SP AusNet's proposed reinforcement capex.

The following sections outline SP AusNet's response to the key issues raised in the draft decision, Nuttall Consulting's assessment and the AER's considerations for the final decision.

Methodological review

In the draft decision the AER agreed with Nuttall Consulting's assessment that SP AusNet's load profile based upon demand in 2007–08 may overstate the risks, particularly in the latter half of the forthcoming regulatory period, and may result in the deferment of some projects. This issue was factored into Nuttall Consulting's weighted probability assessment.

SP AusNet in its revised regulatory proposal did not agree with this assessment. It has undertaken an assessment of load duration curves for 2007-08, 2008-09 and 2009-10, it found that the curves had not changed significantly over that period. Therefore it considered that 2007-08 load duration curves used by SP AusNet to determine its reinforcement requirements for the forthcoming regulatory control period are reasonable and represent load duration curves expected for 50 per cent PoE conditions.[73]

Nuttall Consulting noted in its report that is does not disagree that in most circumstances, when higher loads are occurring, and energy at risk could increase substantially from one year to the next. Nuttall Consulting also considered that when all factors are accounted for, this may result in projects in the latter half of the period being deferred. However Nuttall Consulting also noted that it has placed only a small weight on the load duration curves in its assessment of SP AusNet's reinforcement expenditure forecast.[74]

The AER considers that the load profile used to determine energy at risk will have an impact on the timing of forecast augmentation projects. Consideration in the calculation of energy at risk needs to be given to the change in load profile over time as energy consumption behaviour changes. However it also agrees with Nuttall Consulting that a low weighting be given to the load duration curve assumptions in the assessment of the prudency and efficiency of the reinforcement forecast.

[73] SP AusNet, *Revised regulatory proposal*, p.107.
[74] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 167-168.

Project review

Mooroolbark Zone Substation

The AER in its draft decision agreed with Nuttall Consulting's assessment that there is a moderate to low probability of this project being required as proposed by SP AusNet. This was based on Nuttall Consulting's assessment that a more extensive economic analysis of issues may result in the project scope and timing being further optimised.

In its revised regulatory proposal SP AusNet provided additional information to economically justify the Mooroolbark zone substation proceeding as forecast. In these additional reports SP AusNet argued that the project timing is justified to be constructed in 2014.[75]

Nuttall Consulting assessed the additional material provided by SP AusNet on the proposed Mooroolbark zone substation. It considered that the loss reduction benefits used to justify the project should be around 20 per cent lower than that proposed by SP AusNet. Nuttall Consulting also considered that short term measures could be applied to defer the main project from 2014 to 2016 to ensure the energy at risk clearly justifies the timing. It considered that less than 5 MW of additional relief may be needed to allow for this. Such measures to achieve this could include load transfers, demand management, or embedded generation. Nuttall Consulting considered that SP AusNet's evaluation of its various options had not adequately considered these short term management issues.[76]

Nuttall Consulting also considered that given that the 22 kV feeder overloads impact on the economic justification for the project, it did not consider that SP AusNet had adequately assessed alternative options associated with managing these overloads. Nuttall Consulting also considered that as there will be reliability improvement that will occur as a result of this project. The AER considers that, if funded on the timing proposed by SP AusNet, this project could result in an increase in reliability, contrary to the incentives provided by the Service Target Performance Incentive Scheme. Therefore a capex allowance is clearly not required to fund the overall project.[77]

The AER assessed the additional information provided on the Mooroolbark zone substation and has considered the Nuttall Consulting assessment. The AER also undertook an assessment of the maximum demand forecasts driving demand at the zone substation level and found them to be reasonable. The AER also considers that the energy at risk is not sufficient to justify this project proceeding as forecast. The AER agrees with Nuttall Consulting that given the project is only marginally justified in the forthcoming regulatory control period that short term measures could be used to defer this augmentation, including load transfers, demand management, or embedded generation, having regard to capex factor (10).

The AER therefore considers based on the energy at risk used to justify this project and the other issues identified with this project that it can be economically deferred by

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[75] SP AusNet, *AMS 20-301 - Network Planning Report - New Mooroolbark Zone substation*, July 2010.

[76] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 169-172.

[77] ibid., pp. 169-172.

two years from 2014 to 2016. The AER considers that deferring this project from 2014 to 2016 is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the AER's approach to assessing reinforcement, and the AER has had regard to the capex factors outlined in section P.2.1.

Wollert Zone Substation

The AER in the draft decision agreed that there was a moderate probability of this project proceeding as forecast by SP AusNet. SP AusNet in its revised regulatory proposal provided additional information on this project in appendix AMS 20-314 and an economic assessment of the options for the proposed augmentation.

Nuttall Consulting undertook a detailed assessment of the additional information provided for the proposed Wollert zone substation. It considered that the energy at risk analysis presented by SP AusNet does not consider the potential for load relief, which could delay the project. Nuttall Consulting considered that if around 5 MW of further load relief can be found then the optimal timing would be just prior to 2015-16. This is based on the view that in SP AusNet's Network Planning Report for this project, it stated that there is up to 10 MVA of available load transfer from Epping to surrounding substations. Nuttall Consulting also considered that temporarily allowing for a small amount of energy at risk at South Morang would also allow for a deferment of the Wollert zone substation.[78]

Nuttall Consulting considered that as reliability improvements will occur as a result of undertaking this project, a capex allowance is not required to fund the overall project. Based on this assessment Nuttall Consulting considered that this project could be deferred by one to two years.[79]

The AER assessed the additional information provided by SP AusNet on the Wollert zone substation and has considered the Nuttall Consulting assessment. The AER has also reviewed maximum demand forecasts at the Epping zone substation and has considered them to be reasonably consistent with historical growth rates.

The AER considers that based on the information provided for this project that there is potential for load relief at the Epping zone substation that have not been fully considered by SP AusNet. The AER agrees with Nuttall Consulting that there is potential for load transfers away from the Epping zone substation, as well as demand management that could defer this project, consistent with capex factor (10). When this potential is considered the AER expects the threshold above which the energy at risk would justify augmentation would be delayed by at least one year.

Based on this assessment the AER considers that this project has not been justified as prudent and efficient expenditure, consistent with the capex criteria. The AER therefore considers based on the energy at risk used to justify the timing of this project and the other issues identified with this project that it can be economically deferred by one year. This assessment is consistent with a total forecast capex that reasonably

78 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 172-174.
79 ibid., pp. 172-174.

reflects the capex criteria, with the AER's approach to assessing reinforcement, and the AER has had regard to the capex factors outlined in section P.2.1.

2nd 66 kV line from Kilmore South and Seymour Zone Substations

The AER in its draft decision agreed with the Nuttall Consulting's assessment that there was a moderate probability of this project proceeding. SP AusNet in its revised regulatory proposal submitted that this project is required in the forthcoming regulatory control period. SP AusNet considered that the project's timing justified the costs and the alternatives have been adequately considered. SP AusNet provided additional information in its revised regulatory proposal in AMS 20-302, and an economic evaluation of the proposed augmentation.

Nuttall Consulting undertook a detailed review of the revised material and considered that SP AusNet had not justified the expected cost of unserved energy at risk as being reasonable. Based on its assessment of the load duration characteristics of the zone substation that the loss reduction benefits used to justify the project should be around 20 per cent lower than that proposed by SP AusNet. With regard to line outage probabilities, Nuttall Consulting maintained the view SP AusNet's assumptions may overstate the risks. It also considered that a small amount of additional reactive support would be required to defer this project by one or two years.[80]

However Nuttall Consulting considered that based on the options analysis undertaken by SP AusNet that the proposed augmentation is the preferred option. Based on its overall assessment Nuttall Consulting considered that this project could be prudently deferred by one to two years.[81]

The AER considers that there are some concerns with the energy at risk to justify this project. The AER agrees with the Nuttall Consulting's assessment that the loss reduction benefits should be specific to the zone substation load duration curve, which results in a 20 per cent reduction in the loss load factor. It also agrees that options to manage the project for an additional one or two years have not been fully explored. The AER considers that based on this assessment the AER considers that this project is not justified as prudent and efficient, consistent with the capex criteria. The AER considers that based on the reasons discussed above, it is prudent to defer the expenditure for this project by one year from 2015 to 2016. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

Zone substation transformers

In the draft decision the AER agreed with the assessment undertaken by Nuttall Consulting that there was a moderate probability of this program of zone substation transformers being required as forecast.

SP AusNet in its revised regulatory proposal did not agree with the AER's draft decision on these projects and has provided network planning proposals and economic

80 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.175-178.
81 ibid., pp.175-178.

analysis for the zone substation transformers reviewed by Nuttall Consulting for the draft decision, including at Ferntree Gully, Kilmore South, Moe and Clyde North.

Nuttall Consulting assessed the additional material provided for each transformer and considered that SP AusNet had not provided information to demonstrate that the possible transfer will not be available which could defer the projects. It also considered that these load transfers would be included in later risk assessments that will be applied when undertaking a more rigorous evaluation of the projects.[82]

The AER considers that Nuttall Consulting has undertaken a detailed analysis of the proposed augmentations. The AER has also undertaken a detailed review of the maximum demand forecast at these zone substations. This review found them to be reasonable with the exception of the growth forecast at the Moe zone substation, which was not justified as consistent with historical trend.

The AER considers that the potential for load transfer away from these zone substations has not been fully considered by SP AusNet. Based on this assessment the AER considers that energy at risk used to justify these augmentation projects could be managed for 1 year longer than that proposed by SP AusNet. The AER therefore considers that the proposed transformers have not been justified as prudent and efficient. The AER considers that it is reasonable to defer these projects by 1 year in the forthcoming regulatory control period. For Clyde North and Moe transformers this results in a shift from 2013 to 2014. For the Ferntree Gully transformer this results in a shift from 2012 to 2013 and for Kilmore South transformer this results in a transfer from 2011 to 2012. This assessment is consistent with a total forecast capex that reasonably reflects the capex criteria, with the AER approach to assessing reinforcement, and has had regard to the capex factors outlined in section P.2.1.

Distribution transformer program

The AER agreed with Nuttall Consulting's recommendation that there is a moderate probability of this program proceeding as forecast. This allowed for existing levels of upgrades, with some allowance for escalation in volumes.

SP AusNet in its revised regulatory proposal considered that Nuttall Consulting did not allow for an existing recurrent expenditure in this category. It also considered that this project has been approved and is planned to be completed by 2012. SP AusNet provided further detail on this project in its reinforcement capex - response to the draft decision document.[83]

Nuttall Consulting assessed the additional material provided for this project and considered that it has not addressed its main concern which is whether the program will efficiently address failure rates. It also considered that SP AusNet had not addressed its concerns with the scale of the program, and the short time frame in which it is proposed. Nuttall Consulting also considered that it was not clear whether SP AusNet had allowed for further optimisation to occur that may reduce the number of transformer augmentations. However Nuttall Consulting also considered that there should be some allowance for some level of replacement to occur and the additional

[82] ibid., p.179.
[83] SP AusNet, *Revised regulatory proposal - Reinforcement capex - response to draft decision*.

expenditure spread over a 7 year period. This would result in a risk profile that is more in line with a trending down of currently accepted risks.[84]

The AER considers that the additional material provided by SP AusNet has not addressed that the program will efficiently reduce failure rates. Therefore it considers that the program forecast by SP AusNet has not been economically justified as prudent and efficient expenditure. The AER also agrees with the Nuttall Consulting that a trending down of acceptable risk is reasonable rather than a step down in a short period of time. Given this the AER considers that an allowance for this program be made based on historical costs, with the additional expenditure spread over 7 years , consistent with capex factor (5). The AER therefore considers that an allowance for this program of $36.3 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

Other projects

Based on concerns raised by SP AusNet that Nuttall Consulting had not reviewed enough projects in the first half of the forthcoming regulatory control period, Nuttall Consulting undertook an assessment of additional projects that had not been reviewed in detail prior the draft decision. SP AusNet provided further detailed information on some specific projects in response to a request from the AER.[85] The following section outlines Nuttall Consulting's assessment of these projects and the AER's consideration for the final decision.

Thermal uprate to Moe/YPS-WGL

Based on its assessment of the additional material on this project Nuttall Consulting considered that the energy at risk does not justify this project proceeding before 2014. It considered that SP AusNet did not allow for the thermal overload, but assumes a high probability of voltage collapse. It also considered that the energy at risk at Warragul zone substation would not justify a $2.3 million project until 2014-2015. Nuttall Consulting therefore considered that a 2 year deferment for this project is possible.[86]

The AER has reviewed the material provided on this project. It agrees that the energy at risk has not been justified as reasonable, based on Nuttall Consulting's findings that the energy at risk at Warragul does not support the proposed augmentation. Therefore the AER considers that the timing of this project has not been justified. It considers that based on the energy at risk that this project can be prudently deferred by 2 years from 2012 to 2014. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

KLO-DRN new 66kV line

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84 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.180-182.
85 SP AusNet, Response to information requested 17 August 2010, 24 August 2010.
86 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p.184.

Nuttall Consulting reviewed the additional material provided by SP AusNet on this project. Nuttall Consulting does not consider that this project is necessary until Wollert comes into operation, yet the project is reliant on Wollert coming into in service for 2012-13. Nuttall Consulting also reviewed the various options, however found that the proposed option is likely to be the preferred option.[87]

The AER considers that based on the information provided that SP AusNet has adequately considered the alternative options for this project. However the AER agrees with Nuttall Consulting that this project is not required until the Wollert zone substation comes into operation, which the AER considers should be deferred until 2014. Based on this assessment the AER considers that it is prudent to defer this project from 2012 until 2014 as the energy at risk does not justify this project proceeding until Wollert is in operation. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

LGA-WGI and MWTS-LGA 66 kV line upgrades

Nuttall Consulting reviewed the additional information provided by SP AusNet on this project. Based on its assessment it considered that the need for this project is justified based on the value of energy at risk. However Nuttall Consulting also considered that, in part, this project should result in an improvement in supply reliability.[88] The AER agrees that, if funded on the timing proposed by SP AusNet, this project could result in an increase in reliability, contrary to the incentives provided by the Service Target Performance Incentive Scheme.

The AER has reviewed the additional information provided by SP AusNet. The AER does not consider that the timing is significantly impacted by the potential reliability improvement noted by Nuttall Consulting. Based on this assessment, it agrees with Nuttall Consulting that the energy at risk justifies the project proceeding as forecast by SP AusNet. Therefore the AER is satisfied that this project is justified as prudent and efficient expenditure, consistent with the capex criteria.

HV feeder projects

Nuttall Consulting reviewed the additional information provided by SP AusNet, and considered that the feeders indicated and the overall feeder loadings at the substations support that some HV feeder augmentation will most likely be required. Nuttall Consulting also noted that the planned new feeders could involve reliability improvement benefits. Based on Nuttall Consulting's estimate of a 10 per cent improvement in SAIDI for a feeder being relieved, in most cases the projects could result in improved reliability.[89] Nuttall Consulting though, was unable to identify with precision which projects would be affected by this consideration.

The AER has reviewed the additional information provided by SP AusNet. It considers that given the loading on the network that it is reasonable for SP AusNet to undertake these works. However, the AER also agrees with Nuttall Consulting's

[87] ibid., p.185.
[88] ibid., p.185.
[89] ibid., p.186.

finding that the majority of these projects are partially justified on the basis of an improvement in reliability. However, given the difficultly in determining which projects should be adjusted due their contribution to improved reliability, the AER has not made any adjustment to these projects. Hence, based on the information provided that the need for these projects is justified, the AER considers that the proposed expenditure for these projects is prudent and efficient, consistent with the capex criteria.

Other programs

The AER notes that SP AusNet proposed $36.5 million in direct costs for the augmentation of overhead powerlines to eliminate the 2,000 overhang spans. This proposed capex is aimed to achieve compliance with the Electric Safety Regulations 2010.[90] The AER does not consider reinforcement to be the key driver for this expenditure and has therefore transferred this expenditure to the environmental, safety and legal capex category.

SP AusNet in its revised regulatory proposal considered that the AER rejected its demand management proposal without giving it any consideration. It considered this to be improper decision-making, and reflects an inappropriate and unreasonable application of the AER's discretion under the NER. If the AER again rejects the demand management and non-network solutions in its final decision, an additional $15.8 million is required in reinforcement capex.[91]

The AER also notes the concerns of CSIRO which expressed disappointment that the draft decision did not mention SP AusNet's network storage demonstration project and encouraged the AER to consider this project.[92] The AER accepts that this was an oversight in its draft decision.

Regarding the proposed $3.18 million in demand management the AER considers this expenditure to be reasonable given SP AusNet's argument that this expenditure would defer $15.8 million of capex.

AER conclusions

The AER has assessed SP AusNet's revised regulatory proposal for reinforcement capex and the additional material proposed to support the economic justification for the projects reviewed by Nuttall Consulting and other material projects forecast for the forthcoming regulatory control period.

The AER has taken into account the review undertaken by Nuttall Consulting and its key findings from its assessment of SP AusNet's revised regulatory proposal. The AER has also reviewed the maximum demand forecasts that are driving the key augmentation projects. Based on this review the AER considers that the proposed maximum demand forecasts by SP AusNet used to generate its energy at risk calculations are reasonable. Refer to the growth forecasts chapter for further detail of this assessment.

90 SP AusNet, *Revised regulatory proposal*, p.109.
91 SP AusNet, *Revised regulatory proposal*, p.110.
92 CSIRO, *Proposed network storage demonstration by SP AusNet and the CSIRO*, 19 August 2010.

Based on the assessment of major augmentation projects and methodologies used to determine the reinforcement the AER considers there are a number of issues with the economic justification for the timing of the projects and with the economic options considered for SP AusNet's proposed reinforcement capex. The AER considers that the obligation on a DNSP is to maintain reliability of its network. The regime further provides incentives to improve reliability. Therefore, it is not reasonable to justify a project based on the benefits received through improved reliability. Regarding the distribution transformer program the AER agreed with Nuttall Consulting that SP AusNet has not demonstrated that the program will efficiently reduce the failure rates of transformers and therefore realise the necessary benefits to justify the cost of the program.

The AER considers that the proposed forecasts do not adequately take account of the further detailed analysis and refinement of projects that results in the actual projects that are required and undertaken in the forecast period. This is consistent with previous regulatory control periods where actual expenditure has been considerably less than what DNSPs have originally forecast.

Based on this assessment, the AER is not satisfied that SP AusNet has justified that its forecast of reinforcement expenditure reasonably reflects the efficient cost of achieving the capex objectives, specifically to meet or manage the expected demand for standard control services over that period.

This assessment is consistent with the capex criteria and the AER approach to assessing reinforcement outlined section in section P.2.1. In doing so this assessment has also had regard to capex factor (1), in taking into account the information in SP AusNet's regulatory proposal; capex factor (3), whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting; capex factor (4) in assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP; and capex factor (10), where the AER has taken into account the extent to which SP AusNet has considered and made provision for efficient, non-network alternatives.

In determining an alternative forecast of reinforcement capex the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast of reinforcement capex, including more recent 2009 historical data. However the AER also acknowledges that based on the loading of the SP AusNet network that an increase in reinforcement capex is required in the forthcoming regulatory control period.

The AER has considered Nuttall Consulting's detailed review of methodologies used to derive the reinforcement expenditure forecasts and that the sample of projects reviewed is a reasonable representation of the issues that exist across the entire reinforcement forecast and across each year of the forthcoming regulatory period. The AER considers this methodological and project review has provided a reasonable assessment of the issues that exist across each category of SP AusNet's reinforcement forecast. The AER has therefore taken into account Nuttall Consulting's findings from its review to determine the prudency and efficiency of the major augmentation projects reviewed. However as described above the AER considers that Nuttall Consulting's weighted average probability assessment requires further testing to be used as an appropriate methodology to determine a reasonable forecast of reinforcement capex within the requirements of the rules.

Based on its assessment of SP AusNet's revised regulatory proposal for reinforcement, the AER considers that an allowance for reinforcement expenditure of $288.3 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this level of expenditure will allow SP AusNet to meet the needs and other obligations as outlined in the NER and NEL. In its consideration the AER has had regards to the revenue and pricing principles.

This appendix has assessed the proposed allowance for reinforcement expenditure which is one component of SP AusNet's proposed total forecast capital expenditure. The AER considers that the level of expenditure determined in this appendix is consistent with the requirement in clause 6.5.7(c) of the NER that the total forecast capital expenditure reasonably reflects the capital expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capital expenditure. That constituent decision, which should be read together with this appendix, is discussed in the capex chapter 8.

P.2.5.6 United Energy

In the draft decision the AER did not accept United Energy had adequately demonstrated that its proposed increase in reinforcement expenditure was reasonable. It considered that a reasonable estimate would be more in line with historical trend. Based on Nuttall Consulting's assessment the AER considered that there is a moderate probability that the reinforcement expenditure would be required as proposed by United Energy in the forthcoming regulatory control period.

The following sections outline the United Energy's response to the key issues raised in the draft decision, Nuttall Consulting's assessment and the AER's considerations for the final decision.

Methodological Issues

In the draft decision, the AER agreed with Nuttall Consulting that the use of 10 per cent Probability of Exceedance (PoE) weather conditions as the basis for its maximum demand forecasts, would overstate the need for projects by up to three years depending on the load growth.

In its revised regulatory proposal United Energy contended that its use of 10 per cent PoE is consistent with forecasts accepted by ORG and the ESCV. It also contended that the network planning criteria allows for major network elements to operate well above the n-1 rating. Adopting a 50 per cent PoE criteria would substantially increase risk to customer load. UED also considers that the difference between 10 and 50 percent is not critical to the economic justification of the project.[93]

Nuttall Consulting does not accept United Energy's view and still consider the use of the 10 per cent PoE will have some impact on project timing. For all other DNSPs, energy at risk assessments are based upon the 50 per cent PoE and the timing when energy at risk justifies the project cost. In this regard, Nuttall Consulting does not

[93] United Energy, *Revised regulatory proposal*, p.121.

accept that United Energy had adequately justified that the 10 per cent and 50 per cent POE should result in similar energy at risk.[94]

The AER maintains the view that using a 10 per cent PoE maximum demand forecasts will overstate energy at risk, and could alter the timing of projects that are only marginally justified by the energy at risk calculations. Therefore the AER considers that the use of conservative assumptions of maximum demand forecasts needs to be factored into the assessment of the prudency and efficiency of reinforcement capex needs.

Project Review

Templestowe zone substation

In the draft decision the AER agreed with Nuttall Consulting that there is a low probability of this project proceeding as forecast by United Energy as the energy at risk did not justify the proposed timing.

United Energy considered in its revised regulatory proposal that the energy at risk justifies the proposed timing and that it must be completed in the forthcoming regulatory control period.[95] United Energy also provided additional information in a strategic planning paper to support the proposed augmentation.[96]

Nuttall Consulting in its assessment reviewed the additional information provided by United Energy. Nuttall Consulting noted that in its revised regulatory proposal that the energy at risk has increased significantly due to the inclusion of energy at risk on HV feeders. Nuttall Consulting considered that the proposed augmentation would not eliminate all energy at risk on HV feeders. It also considered that based on the revised regulatory proposal the high utilisation of the HV feeders is the main driver of the project. Nuttall Consulting therefore considered that there may be more efficient options to address the HV feeder load issues which could defer the proposed new zone substation.[97]

The AER considers that the main driver of the project appears to be high utilisation of HV feeder works and that the options to address HV feeder works have not been fully examined. The AER also considers that the proposed augmentation may not eliminate all the energy at risk used to justify the timing of this project. The AER considers that based on the issues identified with this project that it is prudent for the timing of this project to be deferred from 2013 to 2015. This assessment is consistent with the AER approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

Keysborough new zone substation

[94] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.198-199.
[95] United Energy, *Revised regulatory proposal*, p.124.
[96] United Energy, *Asset Strategy Strategic Planning Paper - Templestowe new zone substation*, July 2010.
[97] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p.208-209.

The AER agreed with Nuttall Consulting's assessment that there is a moderate probability that this project will be required as forecast by United Energy. These findings were based on issues related to United Energy's use of a 10 per cent PoE maximum demand, and that the project scope may be further optimised.

United Energy in its revised regulatory proposal stated that its planning paper has considered five options and chosen the option with the best net present value. Hence United Energy argued that this project must commence in 2012 and be delivered by 2015. United Energy confirmed that this project has a moderate to high probability of being required. Nuttall Consulting noted in its assessment that the energy at risk for distribution feeders has been included in the revised regulatory proposal. However it considered that the proposed augmentation will not entirely eliminate the energy at risk used to justify the augmentation.[98]

The AER considers that the benefits of this project have been overstated as the energy at risk will not be entirely reduced with the proposed augmentation. The AER agrees with Nuttall Consulting's assessment that the proposed feeder works will not entirely eliminate the proposed energy at risk. The AER considers that based on the issues identified, being that the energy at risk does not justify the timing of this project, it is reasonable that the expenditure for this project be deferred. The AER considers that deferring the commencement of this project from 2011 to 2013 is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

Mentone transformer

The AER in its draft decision considered that this project had a high probability of being required in the next regulatory period. United Energy stated in its revised regulatory proposal that this project should be given a 100 per cent probability of proceeding rather than the 90 per cent allowed for in the draft decision.[99]

Nuttall Consulting considered that based on its assessment that the project is highly dependent on a heightened probability of failure and associated energy at risk due to the relatively poor condition of the existing transformers at Mentone. It however considered that applying a more standard 1 in 100 year probability of failure, the revised energy at risk does not justify the project until after the forthcoming regulatory period. However in spite of these concerns Nuttall Consulting accepted that there is a high probability that the risks will be sufficient to justify the project timing.[100]

The AER considers that United Energy has not justified why a standard probability for transformer failure has not been used in its calculation of energy at risk at this zone substation. The AER considers that using a more conservative assumption regarding transformer failure rates would result in the timing of this project being delayed. The AER in spite of concerns over the input assumptions regarding transformer failure it agrees with Nuttall Consulting that based on United Energy's

[98] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.211-212.
[99] United Energy, *Revised regulatory proposal*, p.124.
[100] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.212-213.

assessment the project timing is justified. Therefore the AER considers this project is justified to be prudent and efficient expenditure. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

Malvern to Burwood sub-transmission 66 kV lines

The AER in the draft decision agreed with Nuttall Consulting's assessment that this project has a moderate to high probability of proceeding as forecast by United Energy.

United Energy in its revised regulatory proposal considered that the MTS-BW-MTS 66kV line is justified on the basis that the transformers at BW substation require upgrading due to potential catastrophic damage. United Energy contended that the any analysis of this project proceeding would require assessment of the remaining life of the old transformers and the risk and consequence of catastrophic failure if they are not replaced in accordance with independent expert advice. United Energy considered that Nuttall Consulting did not undertake this analysis and is therefore unreliable.[101]

Nuttall Consulting reviewed the additional material for this project it considered that based on its assessment of transformer condition in the reliability and quality maintained category, that only one transformer will be at a condition requiring replacement around the timing of this project. Therefore this project could be deferred by 1 to 2 years.[102]

The AER considers that based on the information provided by United Energy that the and the assessment undertaken by Nuttall Consulting that that this project is driven by the condition of existing transformer at the BW zone substation, which has been reviewed in the reliability and quality maintained section of this final decision. Given the AER has considered that the replacement of these assets should be deferred, the AER considers that this subtransmission project should also be prudently deferred. Therefore the AER considers that this project has not justified as project as being prudent and efficient expenditure consistent with the capex criteria. Based on the issues identified, the AER considers that it is reasonable to defer this project by 2 years from 2012 to 2014. This assessment is consistent with the approach to assessing reinforcement, the capex criteria, and has had regard to the capex factors outlined in section P.2.1.

TBTS-DMA-RBD-STO 66kV line

The AER agreed with Nuttall Consulting that this project has a moderate probability of proceeding as forecast by United Energy. This assessment considered that the energy at risk does not justify the project and other low cost alternative could be considered.

United Energy in its revised regulatory proposal provided additional information in a strategic planning paper for this project, which outlines the high energy at risk. United Energy considered that as the load at risk only occurs for 5 or 6 weeks per year, the timing of the project could vary is only load at risk is considered. However United

[101] United Energy, *Revised regulatory proposal*, p.124.
[102] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p.213-214.

Energy considered that voltage profiles and reputational risk need to be considered, and the option of shedding large amounts of load during the peak holiday season is unacceptable to United Energy.[103]

Nuttall Consulting reviewed the additional material provided by United Energy and noted that the energy at risk does not justify the project timing, but rather reputational risk and voltage profiles are the main drivers for the project. It also considered that lower cost options may be the preferred solution. Nuttall Consulting considered that based on the energy at risk the project could be deferred for 1 to 2 years.[104]

The AER considers that reputational risk does not provide an economic justification for this project proceeding as forecast by United Energy. Additionally the AER also considers that the energy at risk does not justify this project proceeding as forecast by United Energy. The AER therefore considers that this project has not been justified as prudent and efficient. Based on the issues identified with this project the AER considers that it is reasonable to defer the commencement of this project by 2 years from 2012 to 2014. This assessment is consistent with a total forecast capex that reasonably reflects the capex criteria, with the AER approach to assessing reinforcement, and has had regard to the capex factors outlined in section P.2.1.

Distribution substation program

The AER agreed with the Nuttall Consulting assessment that this program had a moderate probability of proceeding as forecast. This assessment was to allow for existing levels of upgrades, with some allowance for escalation in volumes.

United Energy in its revised regulatory proposal considered that Nuttall Consulting had ignored the business case for this expenditure, which has been approved and that the project is already ongoing. United Energy also argued that the field experience confirms that the TLM provides reliable data and is more than 90 per cent accurate in predicting which transformers are overloaded.[105]

Nuttall Consulting assessed the additional material provided in United Energy's revised regulatory proposal on the distribution substation program and considered that the prudency and efficiency of the program has not been demonstrated. This being that the program as not been economically justified as effectively reducing the failure rates. Nuttall Consulting therefore retained the view that this program that while there appears to be evidence that a planned replacement of the most heavily loaded transformers may be required. However it does not consider that United Energy has adequately addressed its concerns with the scale of the proposed program. Based on this assessment it considers that it is reasonable to assume that historical expenditure is allowed for but the additional expenditure is spread over 10 years. Nuttall Consulting also considered that staging of the program would result in more of a trending down of acceptable risks rather than the step down over a short period as proposed by United Energy.[106]

[103] United Energy, *Revised regulatory proposal*, p.125.
[104] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review, October 2010*, pp.214-215.
[105] United Energy, *Revised regulatory proposal*, p.125.
[106] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp.215-218.

The AER considers that the additional material provided by United Energy has not sufficiently justified that the cost of this program will provide the benefits in terms of reduced failure rates in distribution transformers. However based on the assessment of Nuttall Consulting the AER considers that it is reasonable to allow for some escalation in volumes for this program over the forthcoming regulatory period however not to the scale proposed by United Energy. The AER therefore considers that this program has not been justified as prudent and efficient. The AER considers that a reasonable allowance for this program should be based on historical expenditure with the additional proposed program of expenditure spread over 10 years. The AER therefore considers that an allowance for this program of $46.6 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. This assessment is consistent with the approach to assessing reinforcement, and has had regard to the capex factors outlined in section P.2.1.

AER conclusions

The AER has assessed United Energy's revised regulatory proposal for reinforcement capex and the additional material proposed to support the economic justification for the projects reviewed by Nuttall Consulting and other material projects forecast for the forthcoming regulatory control period.

The AER has also reviewed the maximum demand forecasts that are driving the key augmentation projects. Based on this review the AER considers that the proposed maximum demand forecasts by United Energy used to generate its energy at risk calculations are reasonable. Refer to the growth forecasts chapter for further detail of this assessment.

Based on the assessment of major augmentation projects and methodologies used to determine United Energy's reinforcement capex forecast the AER considers there are a number of issues with the economic justification for the timing of the major sub-transmission projects and with the economic options considered for United Energy's proposed reinforcement capex. The AER further considers that the use of 10 per cent PoE for its maximum demand forecasts will overstate the energy at risk used to justify the projects. Regarding the distribution transformer program the AER agreed with the Nuttall Consulting that United Energy has not demonstrated that the program will efficiently reduce the failure rates of transformer and therefore realise the necessary benefits to justify the cost of the program.

The AER considers that the proposed forecasts do not adequately take account of the further detailed analysis and refinement of projects that results in the actual projects that are required and undertaken in the forecast period. This is consistent with previous regulatory control periods where actual expenditure has been considerably less than what DNSPs have originally forecast.

Based on this assessment the AER is not satisfied that United Energy has justified that its forecast of reinforcement expenditure reasonably reflect the efficient cost of achieving the capex objectives, specifically to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

This assessment is consistent with the capex criteria and the AER approach to assessing reinforcement outlined section in section P.2.1. In doing so this assessment has also had regard to capex factor (1), in taking into account the information in

United Energy's regulatory proposal; capex factor (3), whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting; capex factor (4) in assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP; and capex factor (10), where the AER has taken into account the extent to which United Energy has considered and made provision for efficient, non-network alternatives.

In determining an alternative forecast of reinforcement capex the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast of reinforcement capex. However the AER also acknowledges that based on the loading of the United Energy network that an increase in reinforcement capex is required in the forthcoming regulatory control period.

The AER has considered Nuttall Consulting's detailed review of methodologies used to derive the reinforcement expenditure forecasts and that the sample of projects reviewed is a reasonable representation of the issues that exist across the entire reinforcement forecast. The AER considers this methodological and project review has provided a reasonable assessment of the issues that exist across each category of United Energy's reinforcement forecast. The AER has therefore taken into account Nuttall Consulting's findings from its review to determine the prudency and efficiency of the major augmentation projects reviewed. However as described above the AER considers that Nuttall Consulting's weighted average probability assessment requires further testing to be used as an appropriate methodology to determine a reasonable forecast of reinforcement capex within the requirements of the rules.

Based on its assessment of United Energy's revised regulatory proposal for reinforcement, the AER considers that an allowance for reinforcement expenditure of $172.3 million ($2010) is consistent with a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this level of expenditure will allow United Energy to meet the needs and other obligations as outlined in the NER and NEL. In its consideration the AER has had regards to the revenue and pricing principles.

This appendix has assessed the proposed allowance for reinforcement expenditure which is one component of United Energy's proposed total forecast capital expenditure. The AER considers that the level of expenditure determined in this appendix is consistent with the requirement in clause 6.5.7(c) of the NER that the total forecast capital expenditure reasonably reflects the capital expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capital expenditure. That constituent decision, which should be read together with this appendix, is discussed in the capex chapter.

P.2.5.7 AER conclusions

For the reasons discussed and as a result of the AER's analysis of the regulatory proposals consistent with the approach in section P.2.1, and Nuttall Consulting's report recommendations, the AER is not satisfied that the proposed reinforcement capex forecast by CitiPower, Powercor, Jemena, SP AusNet and United Energy reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors outlined section P.2.1. The AER considers that reducing each DNSP's proposed reinforcement expenditure to the expenditure outlined in Table P.6 reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors outlined in section P.2.1.

The AER notes that although the Victorian DNSPs have indicated they have prepared their capex forecasts on a detailed project-by-project basis, and the AER has for the most part assessed expenditure in this way, the AER's conclusions relate to a total forecast capex allowance for this capex cost category. Within the approved total capex allowance, each DNSP retains discretion regarding the allocation and expenditure of capital. The AER expects each DNSP to be responsive to changing conditions in order to meet customer requirements while managing and operating the network in accordance with good electricity industry practice. If any matter arises which requires a DNSP to reorder its priorities then it is appropriate for the DNSP to do so.

Table P.6 AER conclusion on reinforcement capex for Victorian DNSPs ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	44.8	40.7	50.5	36.2	32.5	204.7
Powercor	43.5	44.1	47.7	43.0	43.2	221.4
JEN	9.1	6.5	24.0	34.2	19.1	93.0
SP AusNet	55.3	56.8	66.1	51.8	56.3	286.3
United Energy	37.3	36.6	26.6	30.4	40.7	171.6
Total	**189.9**	**184.7**	**215.0**	**195.6**	**191.8**	**977.0**

Note: These numbers are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

P.3 Reliability and quality maintained

This section sets out the AER's consideration of capital expenditure to replace and renew existing network assets to maintain the reliability and quality of supply. With time, network assets age and deteriorate and, if not replaced, may fail, resulting in a deteriorating level of service reliability and quality.

P.3.1 Economic regulation

As noted at the beginning of the capex chapter, each Victorian DNSP proposed an allowance for replacement capex as a component of their total proposed forecast capital expenditure for the 2011-15 regulatory control period. The assessment of replacement capex is relevant to determining whether the AER is satisfied that the total proposed forecast capital expenditure or its estimate of the required capital expenditure reasonably reflects the capital expenditure criteria.

Specifically, this appendix assesses the proposed allowance and what the level of efficient expenditure for replacement capex which a prudent operator, in the circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capital expenditure objectives. This assessment in turn raises issues of the efficiency and prudency of the proposed expenditure as the information from the DNSPs does not support such an increase in expenditure. In particular the AER was doubtful about:

- the drivers of the expenditure or whether the drivers have differed from the current regulatory control period
- the timing of the expenditure
- the delivery or benefits to consumers resulting from the increase in expenditure.

As is discussed in this appendix, the AER has had regard to particular capital expenditure factors that are relevant to this assessment.

P.3.2 Approach

Clause 6.5.7(c) of the NER provides that the AER must accept the forecast of required capex of a DNSP if the AER is satisfied that the total of this capex reasonably reflects, among other matters, the efficient costs of achieving the capex objectives and the costs that a prudent operator in the circumstances of the DNSP would require to achieve the capex objectives.

The NER does not detail a specific approach for assessing prudency and efficiency. Therefore, the AER has adopted an approach whereby it has investigated the need or driver for expenditure, the timing of the expenditure and where appropriate, has used a "business as usual" level of recurrent expenditure as a guide to developing a view about future expenditure. Given the incentive framework established under the NER, the AER considers that revealed costs can be considered as an indicator of efficient expenditure.

The review of the DNSPs’ supporting information was subject to a number of processes. Shortly after the submission of the revised regulatory proposals, the DNSPs were sent a list of questions, where appropriate, to provide evidence to support their forecast expenditure and volumes.

Each of the DNSP’s responses and the evidence provided (including the regulatory proposal) were assessed thoroughly by the AER. The decisions taken were subject to scrutiny, such as engineering judgment, DNSPs’ policies and practices and known type issues. Comparisons were also made with other DNSPs’ forecasts and other assets categories that could be driving the replacements. In conjunction with this process the AER also benchmarked each DNSP's performance against itself and other DNSPs including using its repex model to benchmark the DNSPs replacement volumes.

The AER notes that this process accords with clauses 6.5.7(e) particularly:

- capex factor (1): taking into account the information in each Victorian DNSP's regulatory proposals
- capex factor (2): taking account submissions received from stakeholders
- capex factor (3): whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting
- capex factor (4): assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (5): taking into account the actual and expected capital expenditure, specifically the assets lives achieved in the current period and the volume of asset replacement between historical and forecast.

In determining whether the AER was satisfied of the prudency and efficiency of the forecast capex, the AER considered the information included in or accompanying the building block proposal[107] and the actual and expected capex of the DNSP during the preceding regulatory periods.[108] The AER has had regards to the analysis undertaken by Nuttall Consulting and its own internal analysis.[109]

Where a DNSP was unable to provide robust supporting information or its forecast was inconsistent with the other evidence, the AER adjusted the DNSP's forecast so that it reflected the output of the AER's analysis. Detail of the AER's considerations on the minimum adjustment necessary[110] is outlined in this final decision.

The AER's repex model

In September 2009 the AER engaged Nuttall Consulting to develop a replacement capex forecasting model similar to those applied by Ofgem in the UK. The model produced by Nuttall Consulting forecasts replacement needs at an aggregate level using age as a proxy for the many factors that drive individual asset replacements. The model was also calibrated so that it reflected historical levels and costs.

[107] Clause 6.5.7(e)(1) of the NER.
[108] Clause 6.5.7(e)(5) of the NER.
[109] Clause 6.5.7(e)(3) of the NER.
[110] See clause 6.12.3(f) of the NER.

In assessing previous regulatory proposals, the AER noted that some Network Service Providers utilised complex forecasting models to forecast their RQM capex need. As some of these models were black box propriety models, a robust assessment of the assumption applied within these models were not possible.

For further clarification, the AER has examined the Ofgem's assessment process and has had discussions with Ofgem staff on its replacement modelling. The AER has compared and contrasted its practices with Ofgem's and the results are shown below.

Table P.7 Ofgem and AER assessments and modelling process

	Ofgem	AER
Form of the models		
Theory	Probability theory based model (volumes), using network breakdown into a set of asset types. For each asset type, model predicts replacement volumes based upon:	Probability theory based model (volumes), using network breakdown into a set of asset types. For each asset type, model predicts replacement volumes based upon:
	Age profile (volumes vs installation date)	Age profile (volumes vs installation date)
	Replacement probability distribution (using "survivor" model theory i.e. probability replaced in year y, given it has survived to year x)	Replacement probability distribution (using "survivor" model theory i.e. probability replaced in year y, given it has survived to year x)
	Expenditure for each asset type calculated assuming single, deterministic unit costs i.e. rep volume x unit cost = expenditure	Expenditure for each asset type calculated assuming single, deterministic unit costs i.e. rep volume x unit cost = expenditure
Replacement life probability distribution	Normal Distribution, with standard deviation set to square root of mean	Normal Distribution, with standard deviation set to square root of mean
Unit cost	Fixed value for each asset type	Fixed value for each asset type
Calibration of the model		
Asset type categorisation	Numerous categories (approx 70) defined by Ofgem consistent across DNOs (assume in consultation with businesses). Only 20-30 used for actual modelling.	Numerous categories (40-100) defined by DNSPs and not consistent across DNSPs. Each category mapped to 13 asset classes that are defined by AER.
Replacement life distribution	For individual DNOs, selected the longer of (i.e. giving the lower volumes) of the life derived from:	For individual DNSPs, lives derived from:
	Actual historical volumes and historical age profile	Historical volume and current age profile
	DNOs forecast volumes and current age profile	Use of current age profile as historical age profile not validated to ensure it could be used
	Also industry benchmark derived from weighted average of above derived individual	No industry benchmark derived

	lives. Industry benchmark used to derive DNOs forecasts – i.e. industry benchmark	
Unit cost	Unit cost benchmarking exercise conducted by Ofgem informed by DNO forecast, actual unit costs and the view of consultants (PB power) Considered, numerous factors including: Actual historical unit costs derived through the model Main diver was benchmarking of forecast unit costs.	Use trend in volumes forecasts to trend expenditure. Using weighted average from unit costs and actual DNSP activity code cost data.
Rejection/allowance considerations		
	Focus on asset categories where forecast volumes is higher than model output. DNOs required to provide information that demonstrates the need exists, including:	Focus on asset classes where expenditure/volume appears to be significantly higher than the model. DNSPs are required to provided information that demonstrates the needs, including "fit for purpose" issues when forecast produced by DNSPs models. Information included asset condition information.
	Condition information	Note, much of this information was already requested through the RIN process, but specific information requests were also produced.
	Historical failure rates Also introduced outputs framework which required the DNO to deliver the benefits associated with the allowed volumes	

P.3.3 AER draft decision

The AER's draft decision variously accepted or rejected some of the Victorian DNSPs' identified forecasts for the forthcoming regulatory control period. This is summarised as follows:

- CitiPower: the AER accepted the cross arms, poles, fault related and overhead and underground lines function code forecast. The AER rejected CitiPower's fault level mitigation project, high voltage fuse unit and surge diverters, high voltage switch, reliability improvement, services, transformer replacement, zone substation plant and zone substation secondary systems function code forecasts. Consequently, the AER adjusted CitiPower's RQM capex forecast by $120.7 ($ 2010) million for the forthcoming regulatory control period.[111]

- Powercor: the AER accepted the cross arm, fault related, high voltage fuse unit & surge diverter, services, transformer, poles and other function codes forecasts. The AER rejected Powercor's high voltage switch, overhead and underground line, reliability improvement, zone substation plant, zone substation secondary systems and conductor function code forecasts. Consequently, the AER adjusted Powercor's RQM capex forecast by $108 ($ 2010) million for the forthcoming regulatory control period.[112]

- Jemena Electricity Networks (JEN): the AER accepted the services function code forecast. The AER however rejected JEN's poles, pole top structure, conductors, distribution transformers, underground cables, zone substations, protection, distribution switchgear and reliability maintained (performance) function code forecasts. Consequently, the AER adjusted JEN's RQM capex forecast by $85 ($ 2010) million for the forthcoming regulatory control period.[113]

- SP AusNet: the AER accepted the poles, underground cables, services, high voltage installation function code forecasts. The AER rejected SP AusNet's conductor, cross arms, zone substations plant and recoverable works function codes forecasts. Consequently, the AER adjusted SP AusNet's RQM capex forecast by $112.3 ($ 2010) million for the forthcoming regulatory control period.[114]

- United Energy: the AER accepted the sub transmission communication and protection, network high voltage replacement, services, poles and underground function codes forecasts. The AER rejected United Energy's over head line, sub transmission installation, pole top and performance function codes forecasts. Consequently, the AER adjusted United Energy's RQM capex forecast by $137.1 ($ 2010) million for the forthcoming regulatory control period.[115]

P.3.4 Victorian DNSP revised regulatory proposals

P.3.4.1 CitiPower

CitiPower accepted the AER's draft decision on zone substation replacement, services replacement and fuse and surge diverters and transformer replacement and incorporated the appropriate figures into its revised regulatory proposal.

[111] AER, *Draft Decision*, p. 355.
[112] AER, *Draft Decision*, p. 366.
[113] AER, *Draft Decision*, p. 379.
[114] AER, *Draft decision*, p. 385.
[115] AER, *Draft Decision*, p. 393.

CitiPower disagreed with the AER's draft decision on the fault mitigation program, zone substation secondary replacement, Nilsen low voltage air circuit breaker replacement and reliability replacement.[116]

CitiPower's revised regulatory proposal also submitted the following issues for consideration:

- the AER largely adopted a ‘revealed cost’ approach to assessing CitiPower’s proposed capex and forecasting substitute capex in the draft decision. CitiPower stated that the AER used actual expenditure for the period 2006-08 (together with the Repex Model calibrated with 2006-08 data) to reject and substitute amounts for CitiPower’s proposed reliability and quality maintained capex. CitiPower is concern with this approach as there are reasons why historical capex will not necessarily be indicative of capex going forward.[117]

- the AER's repex model was not capable of forecasting replacement capex that reasonably reflects the capex criteria. CitiPower also considered the AER repex model to be a "black box" propriety mode as the replacement calculation engine comprises a user defined function which was not explained. No further description of the variables is provided and the algorithm is contained in a password protected Visual Basic module with limited explanatory notes to enable the logic to be reviewed.[118]

- PB, CitiPower's consultant, submitted:

  - the AER's basis for rejecting the CitiPower's forecast was based on benchmarking analysis and high level assessments of historical variation

  - the AER did not take into account the supporting information provided by CitiPower. PB noted that the Nuttall report contains little in the way of analysis of the fundamental needs of the businesses to support the dismissal of the asset replacement needs as set out in the Asset Management Plans (AMPs). In place of a fundamental analysis of the needs, risks, and proposed expenditure (prudency and efficiency), Nuttall and the AER has dismissed the replacement capex proposals largely on the basis of an analysis which compares the business proposals to an unreviewed proprietary model that Nuttall acknowledges has not been fully calibrated at a detailed level.

  - the AER's repex model is flawed as: (i) it was not verified by a third party or demonstrated through calibration, (ii) the inputs and assumption were inappropriate, particularly using age as a proxy for replacement, (iii) use of only 2006-2008 data and not 2009-2010 data, and (iv) the lack of detailed consideration of replacement

  - the use of the repex model to determine substitute forecasts did not comply with the NER. PB was concerned with two aspects of the approach taken by the AER:

[116] CitiPower, *Revised regulatory proposal*, pp. 280–308.
[117] CitiPower, *Revised regulatory proposal*, pp. 257–258.
[118] Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, p. 11.

- the substitute forecast is not based on the current regulatory proposal. PB noted that the AER's use of the independently developed repex model results as both the acceptance/rejection criterion and the substitute forecast is inconsistent with the requirement to base substitute forecasts on the submitted regulatory proposal
- the substitute forecast is not demonstrated to be adjusted only to the extent required to achieve the capital expenditure objectives. While the AER has attempted to calibrate an age based forecast, no attempt has been made to demonstrate that the substitute forecast represents the minimum adjustment required, or that the substitute forecast is sufficient to meet the expenditure needs of the businesses over the forthcoming regulatory control period. Instead, the AER has proposed that the businesses are required to demonstrate, not only that the detailed adjustments applied by the AER are unreasonable, but also that the identified risks cannot be managed within the total substitute forecast

- the repex model forecast were similar to CitiPower's forecast if two step change programs (fault mitigation and reliability) were removed from CitiPower's forecast. Therefore the AER should accept CitiPower's forecast
- there was an inconsistent application of substitute forecasts. PB stated that the AER's use of the repex model as the acceptance/rejection criterion results in a total substitute forecast that is inherently biased against the businesses due to the acceptance of forecasts below the repex model results and rejection of those above.[119]

PB also reviewed CitiPower's fault mitigation project and reliability improvement expenditure and considered some of the expenditure to be reasonable. On the fault mitigation program, PB considered, it would be appropriate to allow a component of the proposed expenditure to represent the proportion of the project that is reasonably likely to be justified over the forthcoming regulatory control period, and a probability weighted component to represent the proportion of the project where the efficiency of the option or the timing of its implementation is uncertain.

On reliability improvement, PB noted that the AER has not attempted to identify how this expenditure has been allocated historically, and has not supported the rejection of this expenditure with any analysis of the fundamental need for the proposed expenditure. Given the alignment of CitiPower's proposed replacement expenditure with the repex model results, and Nuttall's implied acceptance of the need for the reliability improvement expenditure, PB considers that the reliability improvement expenditure should be reinstated as part of the CitiPower's baseline proposal.[120]

CitiPower also engaged EA Technology to comment on its application of its forecasting model for zone substation transformers and circuit breakers– the CBRM. Broadly, the EA Technology report discussed four issues:

119 Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, July 2010, pp. 10–19 and 25–38.
120 Parsons Brinkerhoff, *Repex model review: CitiPower - Powercor*, July 2010, p. 19.

- Validity of failure rates used in the model: The AER's draft decision was concerned with CitiPower's used of a default failure rates which did not reflect its own circumstances. EA considered the rates used by CitiPower to be appropriate as they were generally in line with international rates or below the average rates it has experienced.

- Combination of age and condition health indices to give a final health index: The AER's draft decision was concerned about the way in which the health index was calculated. The EA Technology report detailed and reiterated that the calculation conducted to obtain the health index was appropriate as it has taken into account age, observed condition, measured condition, expected life, ageing rate manufacturer type etc.

- The use of factors in addition to measured condition to modified remaining asset life: The AER's draft decision was concerned that other factors (failure rate, age, risk, etc) in the CitiPower's CBRM for were exerting more influence on the output than actual asset condition. EA Technology stated that CitiPower's CBRM use multiple sources of information to forecast remaining life. EA Technology reasoned that condition information alone does not necessary provide the most accurate long-term forecast of remaining life.

EA Technology also compared the repex model with CitiPower's CBRM. Most importantly EA Technology stated that the CBRM model uses future asset condition as the primary driver for asset replacement. In contrast the AER's repex model attempts to determine the appropriate level of investment based on what was invested in the preceding period. EA Technology also noted that Ofgem's age-based survivor model does not necessarily identify the most cost effective investment plan; rather it provides a robust starting point for discussion on appropriate levels of asset replacement. In recognition that asset condition information may influence the final outcome, where the identified level of investment is higher than Ofgem's replacement model, network providers must provide a high standard of information based on robust condition based assessment or other network drivers. EA Technology believes that the CBRM is fit for purpose in this respect. EA Technology also believes that the output from CitiPower's CBRM models:

- supports the views CitiPower that its ageing network require an accelerate level of replacement in the next period

- it correctly identifies the necessary investment to effectively address asset ageing.[121]

Specific comments and issues raised in the revised regulatory proposal concerning particular asset categories are discussed in section P.3.10.11.

P.3.5 Powercor

Powercor accepted the AER's draft decision on overhead and underground line replacement and high voltage and low voltage switch replacement. It incorporated the appropriate figures into its revised regulatory proposal.

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[121] EA Technology consulting, *Review of draft determination*, July 2010, pp. 2–6.

Powercor, however, did not accept the AER's decision on the conductor replacement program, zone substation replacement, zone substation secondary replacement and reliability replacement.[122]

Powercor's revised regulatory proposal also submitted the following issues for consideration:

- the AER largely adopted a ‘revealed cost’ approach to assessing Powercor’s proposed capex and forecasting substitute capex in the draft decision. Powercor stated that the AER had used actual expenditure for the period 2006-08 (together with the Repex Model calibrated with 2006-08 data) to reject and substitute amounts for Powercor’s proposed reliability and quality maintained capex. Powercor is concern with this approach as there are reasons why historical capex will not necessarily be indicative of capex going forward.[123]

- the AER's repex model was not capable of forecasting replacement capex that reasonably reflects the capex criteria. Powercor also considered the AER repex model to be a "black box" propriety mode as the replacement calculation engine comprises a user defined function which was not explained. No further description of the variables is provided and the algorithm is contained in a password protected Visual Basic module with limited explanatory notes to enable the logic to be reviewed.[124]

- PB, Powercor's consultant, submitted:

  - that the AER's basis for rejecting the Powercor's forecast was based on benchmarking analysis and high level assessments of historical variation

  - the AER did not take into account the supporting information provided by Powercor. PB noted that the Nuttall report contains little in the way of analysis of the fundamental needs of the businesses to support the dismissal of the asset replacement needs set out in the AMPs. In place of a fundamental analysis of the needs, risks, and proposed expenditure (prudency and efficiency), the AER has dismissed the replacement capex proposals largely on the basis of an analysis which compares the business proposals to an unreviewed proprietary model that Nuttall acknowledges has not been fully calibrated at a detailed level.

  - the AER's repex model is flawed as: (i) it was not verified by a third party or demonstrated through calibration, (ii) the inputs and assumption were inappropriate, particularly using age as a proxy for replacement, (iii) use of only 2006-2008 data and not 2009-2010 data, and (iv) the lack of detailed consideration of replacement

  - the use of the repex model to determine substitute forecasts did not comply with the NER. PB was concerned with two aspects of the approach taken by the AER:

[122] Powercor, *Revised regulatory proposal*, pp. 267–296.
[123] Powercor, *Revised regulatory proposal*, pp. 274–281.
[124] Parsons Brinkerhoff, *Repex model review: CitiPower - Powercor*, p. 11.

- the substitute forecast is not based on the current regulatory proposal PB notes that the AER's use of the independently developed repex model results as both the acceptance/rejection criterion and the substitute forecast is inconsistent with the requirement to base substitute forecasts on the submitted regulatory proposal
- the substitute forecast is not demonstrated to be adjusted only to the extent required to achieve the capital expenditure objectives. While the AER has attempted to calibrate an age based forecast, no attempt has been made to demonstrate that the substitute forecast represents the minimum adjustment required, or that the substitute forecast is sufficient to meet the expenditure needs of the businesses over the forthcoming regulatory control period. Instead, the AER has proposed that the businesses are required to demonstrate, not only that the detailed adjustments applied by the AER are unreasonable, but also that the identified risks cannot be managed within the total substitute forecast

- there was an inconsistent application of substitute forecasts. PB stated that the AER's use of the repex model as the acceptance/rejection criterion results in a total substitute forecast that is inherently biased against the businesses due to the acceptance of forecasts below the repex model results and rejection of those above.[125]

PB also reviewed some of Powercor's conductor replacement program and reliability improvement expenditure. The AER notes PB comments and report on conductor replacement. Given the Victorian Bushfire Royal Commission the associated expenditure and discussions for this program has been moved to the Environmental Safety and Legal capex category.

On reliability improvement, PB noted that the AER has not attempted to identify how this expenditure has been allocated historically, and has not supported the rejection of this expenditure with any analysis of the fundamental need for the proposed expenditure. Given the alignment of Powercor's proposed replacement expenditure with the repex model results, and Nuttall's implied acceptance of the need for the reliability improvement expenditure, PB considers that the reliability improvement expenditure should be reinstated as part of the Powercor's baseline proposal.[126]

Powercor also engaged EA Technology to comment on its application forecasting model for zone substation transformers and circuit breakers– the CBRM. Broadly, the EA Technology detailed four issues:

- Validity of failure rates used in the model: The AER's draft decision was concerned with Powercor's used of a default failure rate which did not reflect its own circumstances. EA considered the rates used by Powercor to be appropriate as they were generally in line with international rates or below the average rates it has experienced.

[125] Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, July 2010, pp. 10–19 and 25–38.

[126] Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, July 2010, p. 19.

- Combination of age and condition health indices to give a final health index: The AER's draft decision was concerned about the way in which the health index was calculated. The EA Technology report detailed and reiterated that the calculation conducted to obtain the health index was appropriate as it has taken into account age, observed condition, measured condition, expected life, ageing rate manufacturer type etc.

- The used of factors in addition to measured condition to modified remaining asset life: The AER's draft decision was concerned that other factors (failure rate, age, risk, etc) in the Powercor's CBRM for were exerting more influence on the output than actual asset condition. EA Technology stated that Powercor's CBRM use multiple sources of information to forecast remaining life. EA Technology reasoned that condition information alone does not necessary provide the most accurate long-term forecast of remaining life.

EA Technology also compared the repex model with Powercor's CBRM. Most importantly EA Technology stated that the CBRM model uses future asset condition as the primary driver for asset replacement. In contrast the AER's repex model attempts to determine the appropriate level of investment based on what was invested in the preceding period. EA Technology also noted that Ofgem age-based survivor model does not necessarily identify the most cost effective investment plan; rather it provides a robust starting point for discussion on appropriate levels of asset replacement. In recognition that asset condition information may influence the final outcome, where the identified level of investment is higher than Ofgem's replacement model, network providers must provide a high standard of information based on robust condition based assessment or other network drivers. EA Technology believes that the CBRM is fit for purpose in this respect. EA Technology also believes that the output from Powercor's CBRM models:

- supports the views Powercor that its ageing network require an accelerate level of replacement in the next period

- it correctly identifies the necessary investment to effectively address asset ageing.[127]

- Powercor also engaged SKM to conduct a study on the expected magnitude of the opex increase due to the expected ageing of its network for the forthcoming regulatory control period if the draft decision was upheld.

Specific comments concerning particular asset categories are discussed in section P.3.10.12.

P.3.6 Jemena Electricity Networks

Jemena Electricity Networks (JEN) did not accept any relevant aspect of the AER's draft decision. JEN's revised forecast in its revised regulatory proposal, was however, lower than that in its initial proposal. Furthermore, the main drivers of the

[127] EA Technology consulting, *Review of draft determination*, July 2010, pp. 2–6.

replacement for JEN's conductor replacement program, bushfire mitigation program and various services programs were different from the initial proposal.[128]

JEN's revised regulatory proposal noted several concerns. In particular JEN was concern that the capex allowance in draft decision is not sufficient to enable it to meet the capex objectives. JEN further stated that it will not be given a reasonable opportunity to recover its efficient costs as required by section 7A (2) of the NEL. JEN also claimed that the reduced capex allowance will also result in further decline in asset conditions and increased security of supply risks over the forthcoming regulatory control period.

In more detail JEN submitted[129] that:

- In accordance with clause 6.5.7(e), the AER is required to have regard to the information provided by JEN accompanying its building block proposal. JEN considers that the AER has not reviewed it regulatory proposal. JEN further stated that it is impermissible for the AER (or Nuttall) to overlay a decision-making framework or tests for assessing capital expenditure that are inconsistent with the NER – that is the NER requires the AER to start with the service provider’s proposal and assess the proposal by reference to the capital expenditure criteria.

- JEN was also concerned that the AER's draft decisions, has given undue consideration to historical costs over 2006-2008, and insufficient consideration to JEN’s proposal. JEN considers that this will give rise to significant error on the part of the AER – of both a procedural and substantive nature. JEN noted that the AER and Nuttall have treated historical replacement levels of expenditure as being prudent and efficient. Given that this is the case, JEN notes that it would appear that the AER and Nuttall assume that any significant increases in forecast capex above historical levels are based on an unreliable forecasting method.

- JEN stated that its lower spend compared with its forecasts represents a trade off between completing required work and having to fund the cost of that work given that the ESCV allowance was at a significantly lower level. This relationship between allowance and spend brings into question the AER’s presumption that past costs are inherently efficient and prudent. It is logical that past costs will trend to what has been allowed with the result that expenditure is deferred where this allowance is insufficient. JEN considers that collectively the capex factors in the NER seek to avoid this cycle and that excessive reliance on any one factor should be avoided.

- Whilst JEN does not agree with the AER’s and Nuttall’s approach of using historical spend as the primary basis for setting JEN’s forecast capex, JEN notes that the exclusion of 2009 and the estimate for 2010 in any historical trend analysis biases the trend downwards given JEN’s historical spend profile.

- Regarding the AER's adjustments to JEN's allowance, JEN stated that the any adjustment must be on the basis of the regulatory proposal and only amended to the extent necessary to enable it to be approved in accordance with the NER. The

128 JEN, *Revised regulatory proposal*, pp. 153–163.
129 ibid, pp. 153–163

NER does not require a DNSP to forecast categories of capital expenditure on the basis of historical expenditure except to the extent any such departure can be demonstrated to be prudent and efficient.

- JEN notes that the AER's main criticism that JENs' forecasting model inputs and assumptions were not demonstrated to be "fit for purpose" in terms of enabling a "bottom-up" build that was a reasonable estimator of overall prudent and efficient expenditure, appears to be based solely on the observation that "in many cases the models are forecasting significant increases over historical replacement expenditure and volumes". However, this approach ignores the future needs of JEN's business.

JEN also engaged PB to provide an independent report on the AER's assessment process. PB provided the following concerns[130]:

- distribution business' models have been found to be suitable for business asset management practices but inappropriate for the regulatory review process
- there was little fundamental analysis of the business' needs, risks, and proposed expenditure (prudency and efficiency) to support the dismissal of the business' AMP's
- the AER relied on comparisons to an unreviewed age based proprietary model to accept/reject the business proposals and as the basis for the substitute forecast
- the repex model does not align with the specific risks and needs identified in the businesses' AMPs, and does not reflect the specific risks faced by the business over the forthcoming regulatory control period
- considerable discretion has been exercised with regard to selection of a substitute forecast which does not appear to align with the NER
- the application of the repex model as the basis for accepting/rejecting the replacement capex proposals, on an activity code level, creates an inherent bias in the total substitute forecast. The AER rejected all activity code forecasts above the repex model forecast (or historical level) but accepted activity code forecasts which are below, resulting in a substitute total replacement forecast that was materially below both the forecasts proposed by the businesses, and the total replacement forecast predicted by the calibrated repex model.

PB also reviewed the repex model and provided the following commentary:

- use of a normal distribution as the basis for modelling remaining life, rather than the Weibull distribution widely acknowledged in reliability engineering literature was inappropriate
- the assumed standard deviation has not been demonstrated to fit equipment failure profiles

130 Parsons Brinkerhoff, *JEN forecast asset replacement volumes*, pp. 5–19.

- the use of age as a proxy for asset condition is not a reasonable assumption when uniformly applied across all activity codes
- the calibrated lives used by Nuttall show significant variation across the Victorian distribution businesses and are well outside industry expectation. This indicates that the model is poorly calibrated.[131]
- PB also reviewed JEN's forecasting model and it forecasts volumes for poles and poles reinforcement, pole top structures and underground cables and provided the following commentary:
- there are sound reasons for selecting these asset categories and applying a modelling approach to the forecast of asset replacement volumes
- model inputs are a mixture of fact based, engineering assessment or estimation. The fact based inputs into the model appear sound. Engineering assessment inputs into the model are typical of those used by electricity distribution businesses, and estimates have been set to minimise the impact on forecast replacement volumes
- the model inputs used in the 2009 model are similar to those used in the 2004 model. However, the 2009 model will forecast a much smaller volume of asset replacements than the 1999 model due to the input setting for the spread of deferred assets. The revised input setting for the spread of deferred assets should go some way in answering AER’s criticism that JEN has limited success in accurately forecasting its replacement needs using the same model since 2000
- JEN has modified the output of the model to remove overlap in programs of work for pole top structure and pole replacements
- JEN has smoothed the output of the model where the volumes forecast by the model are not likely to be reflective of the actual asset volumes replaced. PB considers that smoothing the output of the model is a sound approach as it does not affect the total number of assets to be replaced over the forecast period and is more likely to reflect the delivery capacity of the business than the unsmoothed output
- for the three assets with material increase in replacement volumes (poles, pole tops and underground cables), PB investigated the asset plans and issues affecting performance of the assets, and concludes that there is considerable evidence to support the increase in replacement volumes.[132]

Specific comments raised concerning particular asset categories are discussed in section P.3.10.13.

[131] PB reviewed the repex model, the underlying code, and the commentary provided in the Nuttall report to the extent possible given that the model relies a proprietary function that is not well documented. Parsons Brinkerhoff, *JEN asset replacement volumes*. July 2010, pp. 11–19.
[132] Parsons Brinkerhoff, *JEN asset replacement volumes*, July 2010, pp. 31–58.

P.3.7 SP AusNet

SP AusNet, in its revised regulatory proposal submitted that, among other matters, the AER had placed undue emphasis in its draft decision on the capex factor in clause 6.5.7(e) (5) of the NER. SP AusNet claimed that this had inadvertently created a significant bias toward forecasting future asset replacement requirements based on historical financial expenditure rather than appropriate consideration of engineering and risk criteria that drive future replacement requirements.[133]

SP AusNet further commented that there appears to be 'bias' in draft decision as it relied heavily upon the unsubstantiated assumptions that past levels of activity reflect efficient behaviour. Given this, SP AusNet's stated that the AER had ignored all other factors outlined in its regulatory proposal. In relation to the repex model SP AusNet submitted:

- historic replacement volumes are not useful in predicting future replacements due to the variability of various contributing factors of replacements
- the expected lives produced from the repex model are not validated against relevant benchmarks
- the use of the square root of the mean of expected life as a measure of the standard deviation for expected life appears mathematically convenient
- the estimation of asset replacement unit cost rates from historical expenditures may are invalid as historical expenditure are recorded for groups of assets
- the repex model has not been accurately calibrated for those assets which are replaced by a new asset having a fundamentally different expected life.[134]

SP AusNet also stated that the AER's top down model (repex model) fails to consider network outcomes or consequences of safety of community, customers and employees, risk of property damage, network reliability & security, and advances in good industry practice. Furthermore, SP AusNet identified several deficiencies with the top down modelling including cohorts within individual asset classes, non-homogenous rates of deterioration, assessed condition and trends in failure rates.[135]

Accordingly, SP AusNet does consider the AER's approach to be prudent or ‘fit for purpose’ as the AER has not considered its recent or forecast asset failure trends, known asset condition nor the subsequent risk and impact on customers and community.[136]

SP AusNet also noted that the draft decision has not accepted its detailed analysis and forecasts that are based upon actual asset condition, performance and risk for these four asset classes. Consequently, the draft decision manually adjusted the standard

133 SP AusNet, *Revised regulatory proposal: reliability and quality maintained, response to draft decision*, p. 15.
134 SP AusNet, *Revised regulatory proposal: reliability and quality maintained, response to draft decision*, July 2010, p. 14.
135 ibid., pp. 12–13.
136 ibid., p. 13.

asset lives in order to calibrate the repex model's output to the levels consistent with historical activity for the respective four asset classes.[137]

This approach is inconsistent with the asset lives deemed prudent by the AER for recent determinations of DNSPs in other states. The draft decision has not presented any evidence of technical or environmental factors that would justify such differences nor is SP AusNet aware of any technical or environmental factors which would give rise to such significant differences.[138]

SP AusNet have calibrated its models with actual asset failure and condition assessment data and cross checked the expected lives against industry standards whereas the repex model has been calibrated to historical expenditure.[139]

SP AusNet also commissioned NERA Consulting to provide an economic assessment of the AER's use of the revealed cost methodology to determine forward looking revenue requirements. NERA's report highlighted several issues[140]:

- The AER has not applied a revealed cost approach to all categories of expenditure. It appear that the draft decision have adopted a mixed approach when forecasting capex for replacement and quality maintenance, referring to both actual capex and to a model of replacement expenditure.

- The draft decision appears to recognise in part the effect of investment policy on replacement capex, since the AER commissioned Nuttall Consulting to develop a replacement capex forecasting model "similar to those applied by Ofgem in the UK". Like Ofgem's model, Nuttall's model forecasts replacement capex using the age of an asset "as a proxy for the many factors that drive individual asset replacements". Such a model would be able to accommodate the current investment policy of each company in accordance with the capex objectives and criteria. However, NERA contend that the AER did not adopt such a policy. Instead, the repex model was "calibrated so that it reflected historical levels and costs". The problem with that approach, is that historical levels of replacement reflect a mixture of past investment policies and do not provide a good indication of future capex. However, the AER states explicitly that it does view historical replacement as a useful basis for forecasting future replacement capex.

- NERA further commented that the AER was in error in that that Ofgem's replacement model was not calibrated to historical levels of expenditure. Thus, the calibration reflected current investment policy, not recent levels of expenditure ("revealed cost"). NERA further noted that Ofgem further engaged in a "detailed analysis of the asset management plans" and did not regard its model as a substitute for such analysis.

- NERA concluded that the "revealed cost" approach is not applicable when forecasting the level of future capex, because past capex is rarely a good indicator of future capex. In applying the "revealed cost" approach, the AER has in practice

[137] ibid., p. 15.
[138] ibid., pp. 15–16.
[139] ibid., p. 17.
[140] ibid., pp. 7–16.

interpreted it loosely; applying it in some cases to asset lives rather than the level of expenditure, but here again the past is a poor indicator of the future, because investment policies have changed recently. The AER accepted that an economic case can be made for this change in investment policy, but overrides it by adopting the historical rate of asset replacement, rather than the new one. The AER also undermined any claim to objectivity for its “revealed cost” approach, by combining it with the subjective choice of parameter. Overall, NERA concluded that there are methodological flaws in the way in which the AER has set allowances for specific items of capex in the draft decision.

P.3.8 United Energy

United Energy did not accept any aspect of the AER's draft decision. Although United Energy maintained its forecasts for the forthcoming regulatory control period, the main drivers for some of these programs were modified in its revised regulatory proposal.

United Energy revised regulatory proposal submitted that United Energy was concerned that the AER's approach to assessing RQM capex was inconsistent with good industry practice. In particular, the AER has not accepted that United Energy's planning and governance processes can be relied upon to deliver efficient and prudent capital expenditure forecasts. Furthermore, the AER also resisted a detailed examination of United Energy's capital expenditure plans. Instead, the review approach has relied on:

- a general proposition that historic capital expenditure provides a good guide to future requirements
- an assertion that as plans progress through the capital approval process an overall saving will be achieved
- a simplistic replacement capex spreadsheet which does not reflect standard asset lives, but instead adopts the asset lives implied by recent expenditure levels.[141]

Furthermore, the AER’s over-reliance on historical data and its inadequate consideration of the expenditure required to meet the capital expenditure objectives leaves United Energy exposed to the likelihood that it will be unable to recover the efficient costs incurred in providing reliable network services to customers. The AER has also failed to recognise that the cost to customers of under-investment far exceeds the costs of over-investment.[142]

Given the reasons outlined above, the AER’s draft decision was not consistent with the requirements of the NER or NEL. In particular, the AER has failed to have proper regard to revenue and pricing principles in section 7A of the NEL, which requires the AER to consider the potential risks of under investment and the over utilisation of the network. Furthermore, the expenditure levels set out in the draft decision would lead

[141] United Energy, *Revised regulatory proposal*, p. 107.
[142] ibid., p. 107.

to a decline in network reliability and compliance, which would also be contrary to the objectives of the NEL and NER.[143]

United Energy's revised regulatory proposal further highlighted that additional RQM capex will be required in the forthcoming regulatory control period due to:

- Deterioration in Service: United Energy stated that it has attempts to maintain reliability via other processes had largely exhausted with any new reliability programs being more costly and less effective. As such asset replacement programs are now the most efficient means to address deteriorating assets to maintain reliability. The AER's approach in using historical expenditure as a key driver ignores the above adopted strategies therefore failing to accurately reflect the condition of assets and therefore under-estimates the amount of expenditure required for replacements.[144]

- Deteriorating trends in reliability: United Energy has analysed its networks reliability performance in the years from 2002 to 2010. United Energy considers that this analysis clearly demonstrates that it the deteriorating trends in its network's reliability.[145]

- Increasing asset failure rates: Data suggests that the number of asset failures in the period of 1999 to 2008 indicates an increasing trend of approximately two per cent per annum. This was consistent with an age profile of the assets where the average age of each asset class is increasing with an attendant trend of declining asset condition. This is entirely consistent with a significant portion of the assets having been installed in the 1960’s and is approaching the end of the physical (and economic) life. The increasing rate of asset failure is an indication that United Energy's network is entering a period in which the requirement for asset replacement will substantially increase.[146]

- Decreasing remaining life of assets: United Energy engaged PB Power to develop a model to test its replacement capital expenditure. However, the AER's draft decision rejected United Energy's forecasts based on this model and instead relied on its repex model. United Energy stated that both the PB and repex models predicted that a significant increase in expenditure over historical levels is required. The two models estimated a different level of expenditure, based on different assumptions about asset life, but both predicted that more assets will be at the end of their lives, and more assets will require replacement (based on condition). As predicted by the models, and as backed up by in-service inspection and an increase in failure rates, the historical levels of expenditure are not sufficient to maintain the assets in their current state. On historical expenditure levels, the number of assets reaching the end of their life and requiring replacement will continue to increase over the next five years. Given the AER's

[143] ibid., p. 107.
[144] ibid., p. 108
[145] ibid., pp. 108–109.
[146] ibid., p. 109.

concerns in the draft decision, for the revised regulatory proposal, United Energy engaged PB to review and comment on its forecast to address these issues.[147]

- Increasing load at risk: The revised regulatory proposal submitted further information regarding the number of zone substations exceeding their 24 hour N-1 rating, sub-transmission loops exceeding their N-1 rating and distribution feeders being loaded above their planning criteria levels.[148]

- Benchmarks: United Energy submitted several benchmarking graphs and argued that it was more efficient than other DNSPs.[149]

- Network Governance: United Energy considers its capital governance documents demonstrate that its RQM forecasts were reasonable, prudent and efficient. United Energy's also submitted that there has been a change in its business strategy. Based on the evidence of deteriorating asset condition and declining reliability performance, this change in strategy is essential to ensure United Energy can meets its obligations under the NEL and NER while continuing to deliver services at standards reasonably expected by customers.[150]

- Other: United Energy also submitted that the AER's approach in relying in historical expenditure was inappropriate. United Energy reasoned that it's methodology for developing RQM capex is more sophisticated and varies depending on the assets type. United Energy does not use an age based model for some categories of equipment. Model inputs reflect network experience, based on known failure rates or estimated failure rates based on asset condition assessments rather than historic expenditure. Condition assessments vary for asset types, and include non-invasive condition assessment and full condition assessment as appropriate for the particular asset. These processes are outlined further in United Energy's revised regulatory proposal. United Energy also acknowledged that its RQM capital expenditure in the current regulatory period has been lower than forecast. United Energy stated that the regulatory regime (and the discipline imposed on UED by private capital and debt markets) provides very strong incentives to control total capital expenditure within the regulatory allowance. However United Energy's overall capital expenditure forecast for 2006-2010 is only slightly below the regulatory allowance.[151]

Having said this United reiterated the points mentioned above that its assets are ageing and that its reliability standards are decreasing. Therefore a high capex allowance will be required in the forthcoming regulatory control period

United Energy provided the following comments regarding the AER's repex model.

United Energy notes that the AER does not provide any analysis to demonstrate that the Victorian DNSP’s historic expenditure is sufficient to maintain current network performance. For example, benchmarks in trends for average asset lives, network

[147] ibid., pp. 109–110.
[148] Ibid., pp. 110–112.
[149] ibid., p. 113.
[150] ibid., pp. 113–114.
[151] ibid., pp. 129–131.

reliability and equipment failure rates could have been used to form an opinion of the prudency of the proposed capital programs. The AER also assumed that the historical level of spend will address simular risks in the future, in spite of the fact that present expenditure levels are resulting in increases in asset age, and increasing equipment failure rate and a reduction in network reliability. United Energy asserted this assumption is fundamentally incorrect and without basis.[152]

The AER's repex model was also calibrated against historical volumes and expenditure for historical years 2006-2008. The repex model assumes a normal distribution of the lives of various assets and adjusted (or “calibrated”) so that the model's asset lives correspond to correct historical expenditure. Unsurprisingly, the model then recommends that the present trend of slowly increasing replacement expenditure is continued, which reflects the historical trend. This is an extraordinary approach where the forecasting model has been designed to deliver a desired result; an approach which United Energy rejected as it was entirely inconsistent with good industry practice and good principles of asset management.[153]

United Energy believes that an aged based model has merit in predicting future expenditure, the sole use of historical expenditure to determine the future expenditure is fundamentally unsound and imprudent for the following reasons:

- the use of 2006-08 expenditure and 2004-08 replacement volumes has biased the result on the low side;
- it results in a wide disparity of predicted asset lives between businesses
- the asset lives which are fundamental to predicted expenditure are not related to actual assessment of asset lives based on observation and evidence based condition assessment.
- the repex model selectively uses the annual average annual historical replacement volumes for 2004-08 and expenditure activity in 2006-08 while ignoring 2009 and 2010 data. United Energy stated that the 2009 data shows that its estimates for 2009 were in line with its actual expenditure. By not including this data the repex model underestimates the cost of replacement by some $46 million.[154]

United Energy also argued that the repex model is unsound as it makes a number of assumptions which are not valid and because it encourages inefficient behaviour which included:

- It assumes no change in the assets condition, their physical environments and obligations of the businesses between regulatory periods.
- It cannot address emerging issues or evidence from test results or trends that become apparent during a regulatory period.

152 ibid., pp. 135–136.
153 ibid., p. 136.
154 ibid.,

- Some assets classes are relatively new and practically no historical replacement has been undertaken,
- It rewards over-expenditure and inefficient behaviours.
- No change in assets condition due to ageing assets and climate change.[155]

Regarding the asset lives used in the repex model, United Energy submitted that the weighted average life calculations of the various assets demonstrates a large variance in weighted average life for the same asset classes between businesses. In general, the repex model spread of asset lives is much larger than that in the data provided by the distribution businesses and with nine out of the 11 asset categories, the Nuttall model produces a greater spread of ages. This indicates that the AER's method of re-setting the life on an asset based on asset replacement expenditure is over simplistic and flawed.[156]

In contrast United Energy determined the useful life of network assets industry-accepted standards and based on:

- manufactures' recommendation
- past experience on our own network
- inspections and asset assessment
- industry benchmarks.[157]

In terms of the assessment process, United Energy restated that the AER's has accepted its forecasts when it was below the repex model forecast. In contrast, the AER has rejected this forecast when it was above the repex model forecast. United Energy argued that this demonstrates a bias that is totally unreasonable and totally inconsistent with any reasonable interpretation of the NER.[158]

United Energy also engaged PB to review its application of the PB replacement model. PB also reviewed United Energy's forecasting model and it forecasts volumes for conductor replacement, poles and poles reinforcement and pole top structures and provided the following commentary:

- There are sound reasons for selecting these asset categories and applying a modelling approach to the forecast of asset replacement volumes.
- Model inputs are a mixture of fact based, engineering assessment or estimation. The fact based inputs into the model appear sound. Engineering assessment inputs into the model are typical of those used by electricity distribution businesses, and estimates have been set to minimise the impact on forecast replacement volumes.

155 ibid., p. 138.
156 ibid., p. 137.
157 ibid., p. 137.
158 ibid., p. 138.

- The model inputs used in the 2009 model are similar to those used in the 2004 model. However, the 2009 model will forecast a much smaller volume of asset replacements than the 1999 model due to the input setting for the spread of deferred assets. The revised input setting for the spread of deferred assets should go some way in answering AER's criticism that "United Energy has limited success in accurately forecasting its replacement needs using the same model since 2000.

- United Energy has modified the output of the model to remove overlap in programs of work for pole top structure and pole replacements.

- United Energy has smoothed the output of the model where the volumes forecast by the model are not likely to be reflective of the actual asset volumes replaced. PB considers that smoothing the output of the model is a sound approach as it does not affect the total number of assets to be replaced over the forecast period and is more likely to reflect the delivery capacity of the business than the unsmoothed output.

- For the three assets with material increase in replacement volumes (poles, pole tops and underground cables), PB investigated the asset plans and issues affecting performance of the assets, and concludes that there is considerable evidence to support the increase in replacement volumes.[159]

United Energy also contracted Utility Engineering Solutions (UES) to review Nuttall Consulting's report.

UES submitted that the methodology employed in the Nuttall Report, the conclusions reached and the recommendations made, are fundamentally flawed from an asset management prospective. UES also stated that a simple manipulation of numbers primarily based on a perception of historical under expenditure appears to be the base driver for the recommendations on funding and puts proper asset management at risk because of funding shortfalls. UES also made the following observations:

- the Nuttall Report attempted to model future asset management needs on trend lines, based on questionable data, instead of focusing on what needs to be done to efficiently maintain the safety and reliability of networks into the future.

- the simplistic approach taken in the Nuttall Report totally ignored the extent and complexity of the asset monitoring, measurement, analysis, investigation and research undertaken by Victorian Network Operators.

- the heavy reliance on historical asset replacement data in the Nuttall Report is naïve as this is not a reliable base for future spending. The mix of assets that will require replacement is in a state of continuing change, which is reflected in the measured changes taking place in asset performance and reliability.

- the Nuttall Report appears relaxed about increasing the risk exposure to failure of key plant items. This view is deeply concerning as it shows indifference to the

[159] Parsons Brinkerhoff, *UED Forecast Asset Replacement Volumes*, July 2010.

consequential impact on safety and reliability and the increased regulatory and environmental risk to be carried by the Victorian Operators.[160]

P.3.9 Submissions

P.3.9.1 Grid Australia

Grid Australia submitted that the AER's approach to assessing revenue determinations appeared to be inconsistent with the framework as set out in the NER. In particular, Grid Australia emphasised that the draft decision:

- appears to rely disproportionately on a 'revealed costs' approach to determine forecast capex, and

- adopted an approach for Victoria which was inconsistent with that applied in other distribution determinations. Grid Australia was concerned that this could undermine regulatory consistency and certainty.[161]

P.3.9.2 Energy Users Coalition of Victoria

The Energy Users Coalition of Victoria (EUCV) was supportive of the AER's draft decision and its approach in assessing RQM capex. EUCV noted that the Victorian DNPSs have consistently claimed more capex than required and also invested less than what was allowed without compromising service standards.

The EUCV submitted that it was concerned that DNSPs were using condition monitoring as a means to retire assets earlier than their actual performance would warrant. EUCV also noted that the regulatory approach provides an incentive for networks to replace assets as soon as their economic life was over.

EUCV disagreed with the DNSPs' assertions that the repex model was an inappropriate tool for assessing future RQM replacement requirements. EUCV noted that the AER had used the repex model to develop a capex allowance, and not to develop a deterministic approach to asset replacement. EUCV stated that there is no limitation on the DNSPs' capex replacements levels (noting the flexibility of the roll forward provisions and the lag in the return should the DNSPs choose to overspend on capex).[162]

P.3.9.3 Consumer Utilities Advocacy Centre

Consumer Utilities Advocacy Centre (CUAC) was supportive of the AER's approach in the draft decision of examining historical expenditure levels. CUAC considered that an examination of trend levels of network expenditure suggests a fairly predictable trend. CUAC was of the view that any ageing network assets should be

[160] Utility Engineering Solutions, *Review of Nuttall report*, July 2010
[161] Grid Aust, *Submission on Vic DB Draft decision 2010-15*, 19 Aug 2010, pp. 2 and 4.
[162] Energy Users Coalition of Victoria, *2010 AER review of Victorian Electricity DBs EUCV response to AER Draft decision*, August 2010, pp. 21–22.

replaced progressively over time to ensure the minimisation of one-off price impacts to consumers.[163]

P.3.9.4 Energy Users Association of Australia

The Energy Users Association of Australia (EUAA) was supportive of the AER's application of the regulatory framework and use of revealed cost approach.

In response to the DNSPs' claims that the draft determination was inconsistent with other AER determinations, the EUAA submitted that the AER's previous determinations were in error. Furthermore, the EUAA considered that the AER's draft decision allowance was relatively high should the AER benchmark the Victorian DNSPs' efficiencies against their peers in the United Kingdom.

In response to the DNSPs' claims that historical cost efficiencies have been exhausted and that historical expenditure should not be used as an indicator for future expenditure the EUAA stated that:

- with respect to exhausted efficiencies, service quality and reliability standards have continued to rise, albeit progressively. In contrast, if all efficiencies were exhausted, then it would be expected that service performance would have decreased. The EUAA noted that the AER's task is to deliver the effects of competitive rivalry in the regulation of monopoly service providers and not to predict future developments that will improve efficiency. By default, productivity gains in the distribution sector should, at the very, least match economy-wide trend rates of productivity improvement - a reduction in real terms of the unit costs of delivered services. A rise in expenditure should only occur if services are expanding or if there is a measureable improvement in the quality of those services.

- with respect to historical information to predict future expenditure, historical performance provides important information underlying the claims that the DNSPs have made to the AER. It also provides information about the errors that regulators may have made in assessing those claims. Furthermore, historical information also allows regulators to understand the incentives underlying the businesses and to ensure that historic regulatory errors are not repeated.

In response to the DNSPs' assertions about the AER's repex model the EUAA responded as follows.[164]

Criticism of the use of the “revealed cost” approach in assessing RQM capex

The EUAA asserted that the DNSPs had, possibly, been misleading by insinuating that the AER relied exclusively on historical expenditure to set future RQM capex and by selectively using inappropriate references in the draft decision.[165]

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[163] Consumer Utilities Advocacy Centre, *Submission in response to the AER draft electricity distribution determination for Victoria and the distribution businesses revised revenue proposals,* August 2010, p. 2.

[164] EUAA, *Submission to the Australian Energy Regulator on its Draft Decision on the Revenue and Price Proposals by the Victorian Electricity Distributors for the Period 2011-2015,* August 2010, pp. 13–14.

The use of age as proxy for the various replacement drivers

The EUAA stated that the intention of the repex model was a way of overcoming the asymmetry of information and resources between the DNSPs and the AER. Furthermore, due to time constraints, it was not possible for the AER to conduct the detailed bottom-up type of review that the businesses claim must be conducted. The EUAA also noted that Ofgem currently uses a similar survivor model in it regulatory determination process.[166]

Asset ages implied by the model are unrealistically long

The EUAA refuted this assertion by citing UK references that counter PB's claims about long asset lives. The EUAA also noted that this was clearly evident in the UK where it can be demonstrated that expected lives of many asset classes have grown due to life extension techniques.[167]

Criticism of the Black-Box nature of the repex model

The EUAA stated that the AER's repex model is open for public scrutiny and the AER and Nuttall Consulting made all data and assumptions available, including the software code in the model.

The EUAA further noted that the DNSPs may be referring to the complexity of the repex model when referring to it as "black-box" in nature. However complexity does not in itself render it a "black-box". It also stated that any model used for forecasting expenditures in a category as large as RQM would necessarily be complex and require a good deal of data processing and calibration.[168]

Claimed inconsistency of Nuttall approach to DNSP's use of CBRM

The EUAA identified that the basis for rejecting CitiPower's and Powercor's forecast was:

- that the models were used by CitiPower and Powercor as a means for identifying and prioritising asset replacement needs
- this was only the first step in their decision process in deciding whether to replace an asset.

Furthermore, according to EUAA's submission, the CBRM cannot be used in determining prudency or efficiency. The EUAA stated that while it accepts that the DNSPs are best placed to make operational decisions about asset replacement, it also believes that the regulator is better placed to determine matters that go to the heart of regulatory settings such as allowed replacement capex.[169]

165 ibid., pp. 25–26.
166 ibid., pp. 27–28.
167 ibid., pp. 28–29.
168 ibid., pp. 29–30.
169 ibid., pp. 30–31.

Criticisms of the use of the 2004-2008 period data

EUAA reasoned that the use of such data is consistent with the repex methodology as described by Nuttall Consulting. That is, the 2004-2008 replacement volumes were used to calibrate the asset life data. Since the actual cost data was only available for the shorter period of 2006 to 2008, only that period was used to set the unit costs parameters of the model.

With respect to the use of the data for 2009 to 2010, EUAA identified that the data was not in final audited form when the AER conducted its review - EUAA noted that the DNSPs only provided estimates. EUAA further asserted that under the regulatory framework, there is an incentive for DNSPs to overstate these estimates and that it was only right that they should not be included in the actual expenditure as this would risk biasing the outcomes to the detriment of electricity consumers.[170]

SP AusNet and NERA's claim of misuse of repex model

The EUAA noted that SP AusNet contracted NERA to provide it with an economic assessment of the inference drawn by the AER regarding elements of the approach said to have been taken by Ofgem, in particular whether the inferences are valid or invalid and to provide an explanation of Ofgem's approach. The EUAA noted that NERA had incorrectly interpreted Ofgem's information paper on its replacement modelling. That is, according to EUAA, the basis and purpose of the AER's repex model was consistent with Ofgem's and the AER applied the same calibration process as the UK regulator. EUAA asserted that the evidence quoted by NERA from Ofgem was the same process as outlined by the AER it its draft decision.

On NERA's second and third statement, the EUAA also noted that the release of the draft determination affords the DNSPs and other stakeholders an opportunity to comment on the AER's proposals and the AER to respond to these, similar to the Ofgem process.[171]

P.3.9.5 EnergyAustralia

EnergyAustralia was concerned that the AER's assessment approach in the draft decision appeared to be inconsistent with the NER. In particular EnergyAustralia submitted that the AER:

- have not given proper regard to the assessment framework prescribed under the NER. EnergyAustralia stated that the AER's approached to rejecting and substituting forecast capex was inconsistent with the NER. In particular, EnergyAustralia stated that the AER had placed undue consideration on historical expenditure while ignoring the other capex factors in clause 6.5.6(e) of the NER.

- has developed new models and high level tests that do not provide a reliable or robust method for determining forecast expenditure requirements. In particular EnergyAustralia claimed that the AER's repex model:

[170] ibid., p. 31.
[171] ibid., pp. 31–32.

    - undermines the transparency of the AER's regulatory approach as not all DNSPs were consulted

    - is not appropriate

- is flawed in the followings respects: in relation to, in particular, its assumptions and input data; the original model appears to provide an anomalous outcome which, according to EnergyAustralia, demonstrates the systemic issues with the assumptions and input data of the model; and the re-calibrated outcomes have been back-solved using inappropriate asset replacement lives.[172]

P.3.9.6 Consumer Action Law Centre

The Consumer Action Law Centre (CALC) noted that the DNSPs have asset life extension programs that would reduce the impact of the "bow wave' of replacement capital.

CALC also recommended that the AER:

- investigate the capacity of each distributor to increase the life of assets consistent with an efficient and effective AMP

- request each DNSP to provide a copy of its AMP to the AER with current assumptions clearly set out so that the AER can evaluate each of them and determine if they are efficient and effective

- develop a standard approach to assumptions and asset lives and require DNSPs to follow such guidelines as the AER chooses to establish for the AMPs

- consider simplifying the approval of capital expenditure with the use of each DNSP's AMP and a forecast of business conditions to set out the expected capital expenditures and if the DNSP proposes capex that was within 2 per cent or 3 per cent of the AER's estimate it should approve the proposal without further analysis. In addition CALC proposed that the AER could monitor the impact of capital investment on service standards and provide cost pass through for circumstances in which DNSPs are unable to maintain service standards within the approved capital allowance.[173]

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[172] EnergyAustralia, *EnergyAustralia's submission on AER's draft regulatory determination for Victorian distributors*, August 2010, pp.1–2 and 4–5.

[173] Consumer Action Law Centre, *Submission to the AER's Victorian draft distribution determination 2011- 2015*, August 2010.

P.3.10 Issues and AER considerations

As it developed the draft decision for RQM expenditure the AER considered all information provided to it by the DNSPs and assessed whether, overall, the forecast of each DNSP's RQM expenditure would deliver outcomes consistent with the capex criteria and factors in clause 6.5.7 of the NER and the national electricity objective (NEO) and revenue and pricing principles (RPP) in ss. 7 and 7A of the NEL, respectively.

The AER considers that the Victorian DNSPs' revised regulatory proposals and some of the submissions have misunderstood or misrepresented the AER's assessment process. In addition, it is evident from these submissions that DNSPs and stakeholders have not entirely understood the AER's use of the repex model. In response, the AER has set out its approach in greater detail so that the assessment of the capex factors can be better understood, including the role of the analytical methods and tools used in the AER’s analysis pursuant to clause 6.5.7(e)(3) of the NER.

P.3.10.1 Approach to assessing RQM capex

As the AER has stated, it has introduced a replacement modelling tool (i.e. the "repex model") to assist it with the review of the Victorian determination. This "model"[174] is explained in this section.

Notwithstanding the use of a replacement modelling tool, the AER maintains that its overall approach in assessing regulatory proposals is consistent with all of its other determinations. That is, the AER reviewed the DNSPs' forecasts and information accompanying each proposal to determine if it was satisfied the information met the capex criteria in clause 6.5.7(c) of the NER, taking into account the relevant capex factors in clause 5.6.7(e) of the NER. The AER then either accepted or rejected the DNSP's forecasts in accordance with clause 6.5.7(c) or (d) respectively. Where a forecast was rejected the AER made the minimum change necessary (in accordance with clause 6.12.3(f) of the NER). The AER assessment process was discussed earlier in the approach section and in section 8.6 of chapter 8 in the final decision.

The role of the repex model in this assessment has been misstated in a number of submissions. The primary purpose of the repex model is as a benchmarking tool employed to screen whether or not the capex criteria is met so that the AER can be satisfied whether to adopt a DNSP's forecast.[175] Reduced to a basic explanation, the repex model is an 'age based survivor model' which is populated with the historical population data for an asset category and produces, based on age, an estimate of the expected number of assets which will require replacement. The AER notes that a number of submissions have raised issues which do not distinguish between the age-based survivor model as employed by the AER and the condition based replacement models which are used by some DNSPs.

The underlying assumption in age based survivor models is that assets have a rate of replacement which varies over time. So, for a given asset the product of the volume of

174 The word "model" is used for convenience.

175 In this way, the repex model constitutes an analysis undertaken by the AER in accordance with clause 6.5.7(e)(3) of the NER.

assets of a given age and the replacement rate ascribed to that asset age is an indicator of the expected number of assets which should be replaced, based on age alone. If the data for each is summed, then an estimate of the total volume of assets to be replaced in a particular category results. The AER is aware that the alternative of proprietary condition based replacement models typically incorporate elements of age based survivor assessment but combined with adjustments based on other factors which most obviously includes condition based data. As such, condition based models are substantially more complex to populate and operate and, because of the proprietary nature of the adjustments contained therein, lack transparency.

The output of the AER's model is a target value which can be compared to the proposal of a DNSP. This approach does not seek to replicate the condition based assessment approach and clearly requires the additional consideration of other factors which the DNSPs have characterised in their submissions as the risks faced by a DNSP to arrive at a meaningful conclusion. The AER agrees with the EUAA that it is not a viable proposition for the AER to conduct a bottom-up build of each asset category.

Where the numbers proposed by the DNSP were similar to the output of the AER's repex model forecast it is likely that age alone is a major driver of the particular replacement need. This view should be uncontroversial. This does not mean that the output of the AER's model mirrors the output of the DNSP's forecast. Small relative differences may exist but if the differences are not considered significant the AER has been disposed towards accepting the DNSP forecast as appearing reasonable. But regardless, the AER has examined the other material submitted to confirm whether this view is sound. Because of the further analysis of the supporting material the AER has not found a need to adopt a particular percentage variation as a test of what is 'similar' but has exercised ordinary judgement when making these comparisons.

Conversely, where significant disparities were apparent between the forecast and the AER's repex model the AER examined the other material submitted by the DNSP to seek to understand why a higher forecast should apply. The AER and its consultant then paid particular regard to the supporting information provided, including, but not limited to, economic analysis, business cases, asset management plans, condition reports and consultant reports.[176] The AER also had regard to the observed practices and outcomes of the DNSP in managing an asset category in the current period.[177] The outcome of this step may be that the AER was satisfied with the forecast and if so, the AER adopted the DNSP's forecast. Where the AER remained unsatisfied with the forecast the AER needed to come to an alternative view.

All replacement models are sensitive to the input data and to the assumptions applied by those operating the model. Although the AER could have sought to independently replicate the results of each DNSP's analysis, to do so would require the AER to purchase and learn to operate numerous different proprietary models and require substantially more data be supplied by each business. This would be a costly and an excessively intrusive process and likely inefficient. Even were it to do so it is unlikely that the proprietary algorithms used would be any more transparent to the AER or to

[176] This reflects certain capex factors such as clauses 6.5.7(e)(1),(2) and (4) of the NER.

[177] This effect was taken into account in the calibration of the repex model outcomes to the observed outcomes of the DNSP for each asset category.

consumers. Alternatively, the AER, at some cost to each of the DNSP, could have required each DNSP to run and re-run its models based on the assumptions and inputs that the AER and its consultants concluded were most appropriate for each DNSP. Again, this would be a resource intensive, costly and intrusive process. Even were such analysis undertaken it could not be established a-priori that the AER could or would be satisfied with the results so produced.

P.3.10.2 Reliance on historical expenditure

The AER has set out in detail in section 8.6 of chapter 8 of this final decision, how it used revealed cost information in its analysis. The AER maintains that its decision whether to accept or reject the DNSP's forecast was based on its detailed review of the DNSP's supporting information by Nuttall Consulting and the AER, submissions received from stakeholders and the advice it received from its consultants. The AER's assessment process and considerations were detailed in the draft decision and section P.3.2 and are further explained in the capital expenditure chapter in section 8.6.[178] In exercising its discretion to reject a DNSP's forecast, the AER has had regard to several capex factors when applicable.[179] Indeed the draft decision included the AER's rationale for exercising its discretion under the NER to reject specific issues including:

- where and when the supporting information provided was found to be deficient, and/or
- where and when the DNSP's forecast were inconsistent with the supporting information
- why the AER considered the forecast to be inappropriate or inconsistent with the NER and NEL criteria and objectives.[180]

P.3.10.3 The integrity of the repex model

The AER notes, in relation to the form of the repex model, that in the view of its consultant, Nuttall Consulting, the model had applied a well accepted probability theory which is widely used and relatively trivial to validate.[181] Furthermore, although the model itself could be considered proprietary[182], the theory behind the replacement algorithm is not.[183] A similar approach is used by a number of other parties including the UK regulator Ofgem, to some extent SP AusNet and by PB UK. Furthermore, Nuttall Consulting noted that the AER undertook some form of comparative analysis

[178] AER, *Draft decision*, pp. 338–339.
[179] Not all capex factors were relevant to the AER's assessment of a particular program.
[180] AER, *Draft decision*, pp. 338–393.
[181] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010,p ; The probability theory means normal distribution theory. Algorithm refers to a set visual basic code used in the repex model.
[182] Can be considered to be the intellectual property of Nuttall Consulting.
[183] The repex model including all source code (algorithm) were released to the DNSPs shortly after the draft decision.

of the repex model against the Ofgem replacement model, and did not find any significant differences conceptually.[184]

Issues and AER considerations

The AER notes the comments raised by the DNSPs and submissions regarding the integrity of the repex model.[185] An age based survivor model is used by Ofgem in the UK.[186] As noted earlier, the AER contracted Nuttall Consulting to develop a model than would assist its investigation of replacement expenditure based on the Ofgem approach. This benchmarking tool is intended to independently test whether the volumes of replacement activity for an asset category are consistent with broad assumptions about asset age and condition. The AER's repex model is not a substitute for detailed technical analysis and the skilled application of technical judgement to estimating future needs. Nor is it a condition based replacement model.

The AER agrees with Nuttall Consulting that the theory behind the replacement algorithm is not new and has been tested by Ofgem and other electricity distribution businesses. The AER does not consider its model to be "black box". Shortly after the draft decision the AER made its repex model and source code available to all Victorian DNSPs. The commercial models employed by DNSPs are not subject to a similar degree of transparency and disclosure.[187]

P.3.10.4 Alignment of risks faced by the DNSP

The DNSPs, in their revised regulatory proposals, argued that the repex model does not take into account any future risks faced by the DNSPs. They asserted that calibrating the model to reflect historical replacements and expenditure would not account for changes to risk in the forthcoming regulatory control period.[188]

Nuttall Consulting considered that while both the DNSPs and their consultants have assumed that risk would escalate in the forthcoming period, Nuttall Consulting found no evidence in its investigation to suggest that this view was valid.[189]

Issues and AER considerations

The AER notes the comments raised by CitiPower, Powercor, United Energy, JEN and their consultants, PB and UES, and EnergyAustralia regarding the risks faced by the DNSPs.[190] However, the AER considers that the objections raised by the DNSPs and their consultants conflate two distinct issues and ascribes to the repex model a

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184 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 32; Nuttall Consulting found that the way in which the Ofgem model were calibrated and being applied were similar to the AER. See section Table P.7.

185 See section P.3.4.

186 Ofgem, *Electricity Distribution Price Control Review Policy Paper*, December 2008; *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009. See Table P.7 for a comparison of the methodology.

187 Emails from AER to CitiPower, Powercor, SP AusNet, JEN and United Energy dated 25 June 2010. JEN's and UED forecasts were based on the PB replacement models which were not supplied to the AER as part of the building block proposal. The algorithm and coding within this model are intellectual property of PB. These codes are also not available for viewing even if the model were made available.

188 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review,* October 2010, pp. 32–33;

189 ibid., p. 32.

190 See section P.3.4.

role it does not seek to address. The first is the proposition that the risks faced by the DNSPs have changed. The AER examined this proposition but was not persuaded by the material submitted that this had been demonstrated.

Neither the initial proposals nor the revised regulatory proposals identified any change to legislation, regulations or licence conditions that required a DNSP to change its approach to the management of replacement activity. No new service standards were introduced that would require a change of management practices. Although climate change was raised as a source of a need to modify replacement practices and policies, the material submitted did not persuade the AER that this was an immediate impact. Climate change is discussed in section 8.6 of chapter 8 of this final decision.

The AER notes though that after the draft decision Victorian regulations made the implementation of Energy Safety Management Schemes compulsory. Prior to this, a DNSP had an obligation to have a scheme and, as prudent business operators, were expected to undertake the activities contained in that plan. Although this may change the risk of prosecution for failure to implement a plan, it did not alter the need nor the expectation that a business would have a plan.

The other claim is that the repex model as employed by AER somehow seeks to measure and account for changed risk profiles. The repex model is a benchmarking tool which seeks to establish the likely volumes of replacement activity based on physical parameters such as age and probability of failure. Risk is not a parameter the model seeks to measure. Risk analysis is a further stage in business management processes which involves taking into account the outputs of a model such as the repex model or a condition based assessment model and conducting a further analysis to optimise a DNSP's response to the assessed risk. The outputs of models such as the repex model are important inputs into risk analysis but the AER's model does not seek to replicate this further process.

Having said that, where the information provided clearly supported a change in risk, and or where other supporting information was in line with other evidence, the AER has accepted the DNSP's forecast. For example, in the draft decision the AER accepted many of SP AusNet's replacement programs as the information SP AusNet provided met the capex criteria and objectives and adequately supported its proposal.

P.3.10.5 The assumption that age is a proxy for condition within the repex model

The DNSPs considered that using age as a proxy for condition was not appropriate when applied across all assets categories. Nuttall Consulting stated that this view assumes a level of “homogenisation” within the asset categories, and does not account for changing drivers.[191]

Nuttall Consulting noted that while both the DNSPs and their consultants have assumed that underlying asset condition and other drivers for asset replacement have changed, Nuttall Consulting found no evidence in its investigation to suggest that this view was valid.[192]

[191] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 33.
[192] ibid,. p. 33.

Nuttall further stated that in some circumstances where asset condition information (or other information) suggested that the repex model would not be a reasonable forecast, Nuttall made an alternative allowance. This was most notable for the SP AusNet zone substation assets. For the Final Decision, Nuttall Consulting has reviewed the revised information and this has resulted in these adjustments occurring in a number of other asset categories.[193]

Issues and AER considerations

The AER notes the comments raised by CitiPower, Powercor, United Energy, JEN and their consultants, PB and UES, and EnergyAustralia regarding the use of age as a proxy to asset condition was invalid.[194] The AER considers that age alone is not a complete description of asset condition. But it should be uncontroversial that as assets age their condition deteriorates. For a single asset, age alone is an unreliable guide to the condition of that asset. However, engineering sampling theory is predicated on the observed reality that across a collection of similar assets it is highly probable that trends will emerge. The AER notes the submission of EUAA that the AER's UK counterpart Ofgem has, in collaboration with UK DNSPs, used an age based survivor model as an analysis tool for some time. Were the AER to rely on age alone to assess asset condition then this criticism may be valid. But, as set out in detail elsewhere in this appendix, the repex model has been used as a screening tool to identify asset categories for closer inspection, not as the sole or even the primary determinant of the AER's view of the replacement need of an asset category.

However, where the information provided clearly supported a change or an increase in expenditure, and or where other supporting information were in line with other evidence, the AER made an alternative allowance. This was evident in the AER's draft decision for SP AusNet's and Powercor's conductor replacement program.[195]

P.3.10.6 Repex model assumptions

The revised regulatory proposals raised several concerns regarding the appropriateness of the probabilistic assumptions behind the repex model. In particular the DNSPs questioned:

- the assumption that the replacement distribution can be represented by a Normal distribution, rather than a Weibull distribution, as is commonly used for reliability modelling
- the use of the square root of the mean replacement age to represent the standard deviation of the Normal distribution.[196]

Nuttall Consulting considered that the assumptions that it had used were reasonable approximations to make in the absence of the more complete data set that would be required to determine a more accurate distribution.[197]

[193] ibid., p. 33.
[194] See section P.3.4.
[195] AER, *Draft decision*, pp. 357–359 and 383–384.
[196] The first point was raised by CitiPower, Powercor, JEN and their consultant PB. United Energy also raised the first issue. The second issue was raised by SP AusNet.
[197] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 34–35.

Regarding the issue behind the use of a Normal or Weibull distribution, Nuttall Consulting did not disagree that a Weibull distribution is often used for reliability analysis, including replacement modelling. However, Nuttall Consulting also considers that its use of a Normal distribution, in conjunction with the calibration that it has undertaken, was appropriate in these regulatory circumstances. In this regard Nuttall Consulting observed that:

- a Normal distribution is used in the Ofgem model; this model has been applied for around the last 15 years in the UK for regulatory purposes
- PB has accepted the use of a Normal distribution in replacement modelling it has undertaken for Ofgem – as far as Nuttall was aware, the PB modelling was the genesis of the Ofgem model
- SP AusNet has also assumed a Normal distribution for the majority of the probabilistic modelling it has applied to support its proposed RQM expenditure.[198]

With regard to the standard deviation, Nuttall Consulting considers that this assumption will tend to understate the standard deviation. Although this may understate replacements due to young assets, it will tend to overstate the replacement needs of older assets. Nuttall Consulting noted that this assumption would result in a conservative estimate of the rates of increase in replacement needs (i.e. overstate volume growth rates).[199]

Nuttall Consulting also noted that this assumption[200] is also applied by Ofgem to allow it to calibrate its replacement model. Furthermore, PB has conceded that in most circumstances the DNSPs were not able to provide standard deviation data.[201] To develop a Weibull distribution for each asset category, additional data is required to derive the parameters that define the Weibull distribution. Nuttall Consulting also stated that it is this difficulty in defining the parameters for such a distribution that is the main reason for most users opting to use the simplification of the normal distribution for regulatory purposes.[202]

In response to the DNSPs' claims that the simplification of these assumptions has led to an understatement of future expenditure, Nuttall Consulting noted that the DNSPs and their consultants did not present any evidence to substantiate this claim.[203] Nuttall Consulting further noted that PB had presented some analysis of different distributions that it considers demonstrates Nuttall Consulting's assumptions understate needs. However, it is not clear how PB developed its Weibull distributions, and as such, it is not clear whether it is reasonable to compare these distributions against Nuttall Consulting's assumptions.[204]

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198 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 34.
199 ibid., p. 34.
200 That a Weibull distribution is difficult to calculate without relevant data.
201 Parsons Brinkerhoff, *Repex model review: CitiPower - Powercor*, July 2010, p. 28; Parsons Brinkerhoff, *JEN forecast asset replacement volumes*, July 2010, p. 15.
202 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 34.
203 Parsons Brinkerhoff, *Repex model review: CitiPower - Powercor*, July 2010; Parsons Brinkerhoff, *JEN forecast asset replacement volumes*, July 2010
204 ibid., pp. 26–29.

Issues and AER considerations

The AER acknowledges the DNSPs' claims that a Weibull distribution would be a better fit for reliability modelling. However, a Weibull distribution requires access to a significantly expanded dataset to enable the corresponding curve to be calculated for each asset category whereas a normal distribution has less substantial data needs and is therefore more readily ascertained.[205] Given the calibration of the repex model, the AER agrees with Nuttall Consulting that using a normal distribution is also reasonable to forecast future replacement requirements. The AER observes that:

- the Weibull distribution is not referred to by any of the DNSPs as a basis of the forecasts provided to the AER
- a Normal distribution is applied by SP AusNet in its replacement modelling
- the Ofgem replacement modelling applies a Normal distribution.

Given the wide application of the Normal distribution to predict future replacements, the AER considers that using a Normal distribution, in conjunction with proper calibration of the repex model, will yield similar results to a Weibull distribution. The PB report submitted by JEN made several claims about differences that can arise between the Weibull distribution and a Normal distribution but PB did not comprehensively explain its assumptions or basis of its calculation.[206] The AER also notes that (and as PB conceded), using a Weibull distribution may be problematic as the DNSPs do not have sufficient data available to conduct detailed modelling of the Weibull distribution. The AER notes that the Weibull distribution may predict higher volumes under some conditions. As the AER has not sought to rely exclusively on the repex model but has had regard to the other material submitted with each regulatory proposal the AER does not consider this criticism to have had an impact on its final decision.[207]

To undertake a Weibull distribution would require substantially more preparation of data and analysis by the DNSPs in the first instance. Only those DNSPs who use a Weibull distribution would have this data available to them and the AER did not consider it warranted to require all DNSPs to incur the costs of producing this data for the AER's benchmarking of replacement activity volumes. Using a Weibull distribution rather than a Normal distribution may give different volumes in each year of the forthcoming regulatory control period but the expected differences are not large. The Normal distribution will tend to return higher predicted volumes earlier than a Weibull distribution which tends to support a DNSP's predicted volumes. The AER considered that for the purposes of its benchmarking this was not a material concern.

In relation to SP AusNet's concern regarding the standard deviation, the AER agrees based on standard statistical theory that this assumption will tend to understate the standard deviation. While this may understate replacements for younger assets, it will

205 See earlier discussion in P.3.10.1.

206 Parsons Brinkerhoff, *Repex model review: CitiPower - Powercor*, July 2010, pp. 26–29; Parsons Brinkerhoff, *JEN forecast asset replacement volumes*, July 2010, pp. 13–16.

207 Parsons Brinkerhoff, *Repex model review: CitiPower - Powercor*, July 2010, p. 12; Parsons Brinkerhoff, *JEN forecast asset replacement volumes*, July 2010, p. 7.

also tend to overstate the replacement needs of older assets. The only practical consequence is that the differences in modelling technique mean that the different outputs produced by the different modelling techniques need to be recognised and some account given to other factors which would explain the difference.[208]

P.3.10.7 Using the repex model output as a substitute forecast

The revised regulatory proposals considered that the repex model cannot be used as a substitute forecast as:

- it is not based upon the current proposal
- it has not been demonstrated to provide the minimum adjustment necessary.

However, Nuttall Consulting noted that, in response to the assertion that the repex model cannot be used as a substitute forecast (because it is not based on the DNSPs' proposals), the modelling was undertaken using information made available through the information obtained by the AER through the RINs that it served on the DNSPs and through the AER's further information requests.

In response to the concern raised by the DNSPs that the repex model had not been demonstrated as providing the minimum adjustment necessary to relevant forecasts, as required by clause 6.12.3(f) of the NER, Nuttall Consulting noted that the calibrated lives generally result in a predicted expenditure increase that are greater than the longer-term historical increases. As such, Nuttall Consulting did not consider the repex model to understated future needs; moreover, Nuttall Consulting considered it a conservative estimate.[209]

Issues and AER considerations

As noted in section P.3.10.1 where the AER is not satisfied with a particular forecast, it must substitute its own forecast modified only to the extent necessary to make a proposal compliant with the NER. This can be a difficult value to determine. As discussed in the next section, for reasons of variations in modelling techniques, calibration assumptions and datasets, there are circumstances where the repex model may over-estimate the required volumes as much as under-estimate. Notwithstanding this, if the AER was to substitute a value less than the volume predicted by the repex model (in the absence of specific reasons to do so) it would be unlikely that such volume could satisfy the requirement of the NER as the adjustment made would, prima facie, exceed the minimum adjustment necessary.[210] The AER considers, therefore, that the volumes predicted by the repex model represent a guide to the minimum, or floor, value for asset replacement activity. This is consistent with good industry practice by a prudent and efficient operator. The AER, however, also tested the predicted values by its consideration of any of the other factors which might warrant an increase or decrease from the repex model output - this included comparison to the current management practices of the DNSPs as they pertained to particular asset categories.

208 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 34.
209 ibid., p. 35.
210 In considering the information provided, the AER considers that the proposed expenditure is not prudent and efficient in accordance with the NER.

P.3.10.8 The use of repex model in accepting or rejecting a DNSP's forecast

Nuttall Consulting noted that some of the DNSPs considered that there was an inherent bias in using the repex model to accept or reject forecasts at an asset category level. This is considered to be due to the view that Nuttall Consulting allowed forecasts that were below the repex model, but rejected those that were above; rather than assessing at a total network level with the repex model.

Nuttall Consulting considered that the above view held by relevant DNSPs is due to a misunderstanding of its assessment process. As noted, the rejection was due to a detailed review of the asset category – not the repex model. As explained by the AER, above, if the detailed review led to an acceptance of some increase then this was allowed. Nuttall Consulting considered that this approach, in principle, should not result in a bias in the forecast. Nuttall Consulting accepted, however, that adjustments from the model outputs only occurred in limited circumstances. Nonetheless, given the point above - Nuttall Consulting considered that at the asset level, the model was most likely overstating needs.[211]

Issues and AER considerations

The AER notes the comments raised by CitiPower, Powercor, United Energy, JEN and their consultants, PB and UES, regarding a notional bias in the draft decision process.[212] The DNSPs stated that the AER and Nuttall had only rejected a forecast when analysis showed a forecast less than that of the DNSPs. However when the DNSPs' forecast was higher than the AER's forecast, the AER rejected the DNSPs estimates. The DNSPs considered this to be this was evidence of bias. Similar to Nuttall Consulting's reasoning, above, the AER considers that there has been a misunderstanding about the AER's review process. That is, the AER's decision to accept or reject a proposed forecast was based on its review of the information on hand, including but not limited to the repex model. The NER requires that the starting point for the review is the proposal of the DNSP. The repex model is a tool which assists in this process but for the reasons discussed herein its output is an approximation of the volume of asset replacement activity and thus is a guide to the likely level of justified activity. Where the AER's analysis suggests that a DNSP's forecast when considered overall appears reasonable and the AER accepts that forecast then substitution of the forecast does not arise. . Clause 6.12.3(f) of the NER, which permits the AER to amend a forecast, only applies where the AER has refused to accept a forecast by a DNSP. If the AER is satisfied with the forecast by the DNSP it must accept the forecast of the DNSP.

P.3.10.9 Accuracy of calibration - asset lives

The DNSPs considered that the calibration of the repex model has not been shown to be appropriate.[213] Nuttall Consulting noted that the DNSPs presented several scenarios to support this view.[214]

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211 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 35–36;

212 See section P.3.4.

213 The calibrated lives are higher than other Australian DNSPs or so called industry standards.

214 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 36–37;

Nuttall Consulting accepted that that the calibrated lives in the repex model are variable and longer than many benchmarks. However Nuttall Consulting does not consider that this demonstrated that the repex model was not fit for purpose.[215]

Nuttall Consulting noted that it had considered this issue in its report and concluded that the benchmark lives would have considerably overstated the proposed replacement needs of the DNSPs. If DNSPs actively replaced assets based on benchmark lives this would be apparent in the rate of replacement of ageing assets in the current period. It was consistently the case that the rates of asset replacement were substantially lower across asset categories and across DNSPs. Based upon other modelling that it undertook for the AER in developing the repex model, it was also seen that these lives would have significantly overstated historical expenditure from that which actually occurred. Nuttall also noted that the replacement model used by the ESC in 2000 to set the DNSPs allowance also significantly overstated replacement needs from that which eventuated when benchmark lives were used.[216]

Regarding calibrated lives, although the DNSPs advanced an argument that the repex model did not demonstrate a "goodness of fit" Nuttall Consulting noted that no metrics that would define the “goodness of fit” were provided by the Victorian DNSPs to support this proposition. In its calibration exercise, Nuttall Consulting noted the calibration exercise did result in forecast expenditure being in line with the historical trend – in fact it was slightly above the historical trend. More importantly, Nuttall Consulting found that lives calibrated to historical expenditure were a much more accurate predictor of the actual future RQM expenditure than the benchmark lives.[217]

Nuttall considered that this was compelling evidence that using benchmark lives in such an age-based replacement models would most likely significantly overstate needs. Nuttall Consulting also noted that the DNSPs did not provide any useful opinion on this issue. Furthermore, Nuttall Consulting noted that no studies were presented to show what lives (and probability distributions) would reflect historical expenditure in an attempt to demonstrate a better “goodness of fit” for alternative assumptions.[218]

Finally, Nuttall Consulting noted that United Energy questioned the accuracy of the calibrated model output as it did not predict a “bow wave” of expenditure. Nuttall Consulting noted that replacement models, using the benchmark lives, have predicted fairly significant “bow waves” of expenditure that have not eventuated. As noted in its report (Fig 14), the calibrated repex model is still predicting a fairly significant increase in expenditure over historical levels. Furthermore, this increase may continue over the next 10 to 20 years i.e. the model predicts a “bow wave”, but it is far more gradual than suggested by United Energy.[219]

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215 ibid., p. 36.

216 In 2000 the ESCV used the PB model and the DNSPs benchmark lives to set the RQM capex allowance. As can be seen in Figure P.3 to Figure P.5, this allowance was significantly higher than actual expenditure (actual replacement as a result of age).

217 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 36.

218 Ibid., p. 36.

219 ibid., p. 37.

Issues and AER considerations

The AER notes the DNSPs and submissions by stakeholders concerning the appropriateness of asset lives. The AER has reviewed the information provided by the DNSPs. While several views were expressed, no studies were provided to support the DNSPs' alternate views. Given the historical volumes of replacements, the AER agrees with Nuttall Consulting that the benchmark lives also overstated the DNSPs' replacement needs. On the other hand, the EUAA cited a number of studies that report the success of DNSPs in extending the life span of plant and equipment beyond standard lives.[220] The AER also notes that Ofgem only accepted the Distribution Network Operators (DNOs) asset lives if they were higher then the lives achieved in the previous periods. In addition, the AER also notes that the DNSPs benchmarks lives were also well below the lives of their counterparts in the UK.[221]

As stated in the draft decision the repex model was calibrated with the DNSPs own data. In this calibration process, the AER was able to closely replicate the DNSPs' replacement levels for the previous and current regulatory period.[222]

With respect to United Energy's comments regarding the bow wave effect, the AER draft decision noted that while United Energy's forecast for the current regulatory period predicted a bow wave effect in asset replacement, this scenario did not eventuate given United Energy's volume of replacement to date. UED cites this as the natural consequence of the economic deferral of replacement activity. This may be correct, but if so, it is also evidence that the claimed benchmark lives of assets are conservative and that longer asset lives should apply if an efficient DNSP is managing an asset. Furthermore, the AER notes that the repex model does forecast a bow wave effect, albeit at a more gradual level than implied by United Energy.

P.3.10.10Using 2009 and 2010 data

The DNSPs questioned the appropriateness of the repex model's calibration exercise as it did not account for 2009 actual and the 2010 estimates expenditure. As all DNSPs were expecting a significant increase in expenditure (and replacement volumes) in these years, they considered it important that the review should reflect this.[223]

At the time of the draft decision only estimates for 2009 and 2010 were available. Nuttall Consulting noted that there was instruction from the AER that only audited figures would be relied upon for its analysis. As such 2009 and 2010 figures were excluded from its calibration process.[224]

Since its original review, audited figures for 2009 have been made available. For this final decision, Nuttall Consulting has updated its analysis to account for 2009 data.

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220 EUAA, *Submission to the Australian Energy Regulator on its Draft Decision on the Revenue and Price Proposals by the Victorian Electricity Distributors for the Period 2011-2015*, August 2010, pp. 28–29.

221 http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/May_doc_appx_results.xls

222 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 29–38;

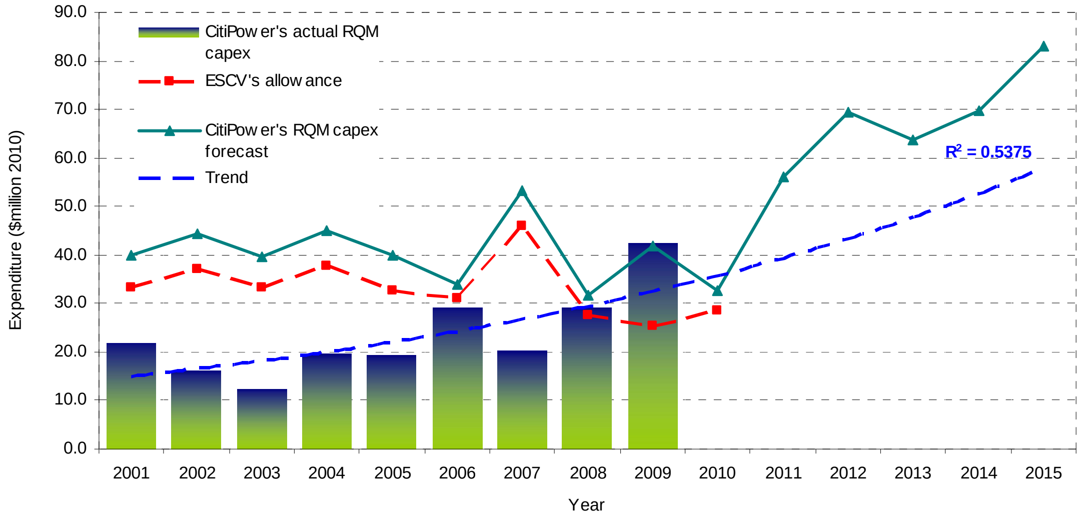
223 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 37.

224 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 37.

Issues and AER considerations

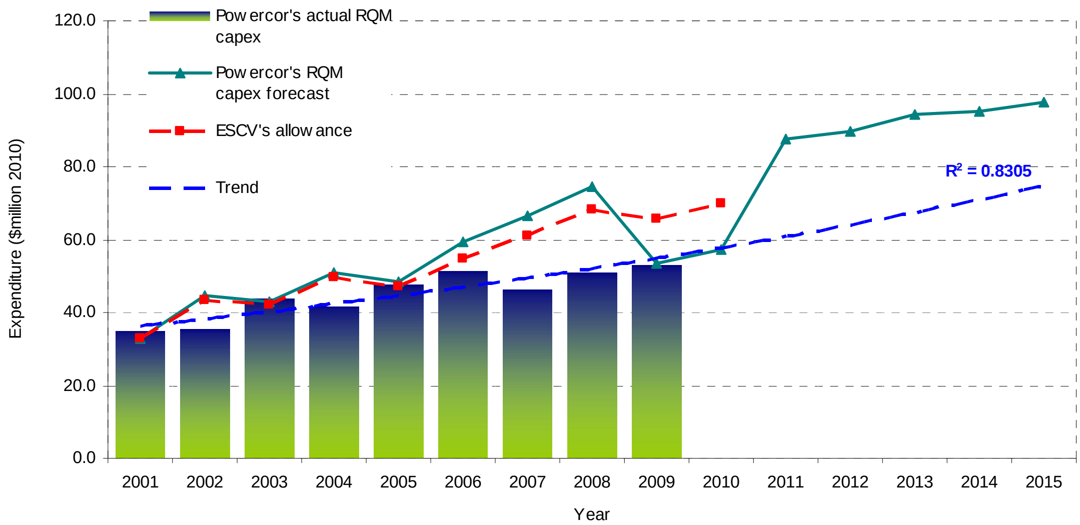
The AER notes the comments raised by CitiPower, Powercor, United Energy, JEN and their consultants PB.[225] At the time of the draft decision the 2009 data was neither audited nor in the form that allowed the AER to appropriately calibrate the repex model. As the AER's analysis of past expenditure relative to forecast allowances demonstrated a tendency for DNSP's to historically over-forecast[226], the AER took a conservative position and excluded unaudited data from the calibration process.

Figure P.1 CitiPower's RQM capex—historical and proposed ($'m, 2010)



Source: RIN templates, ESCV's EDPR 2006–10 and regulatory accounts.

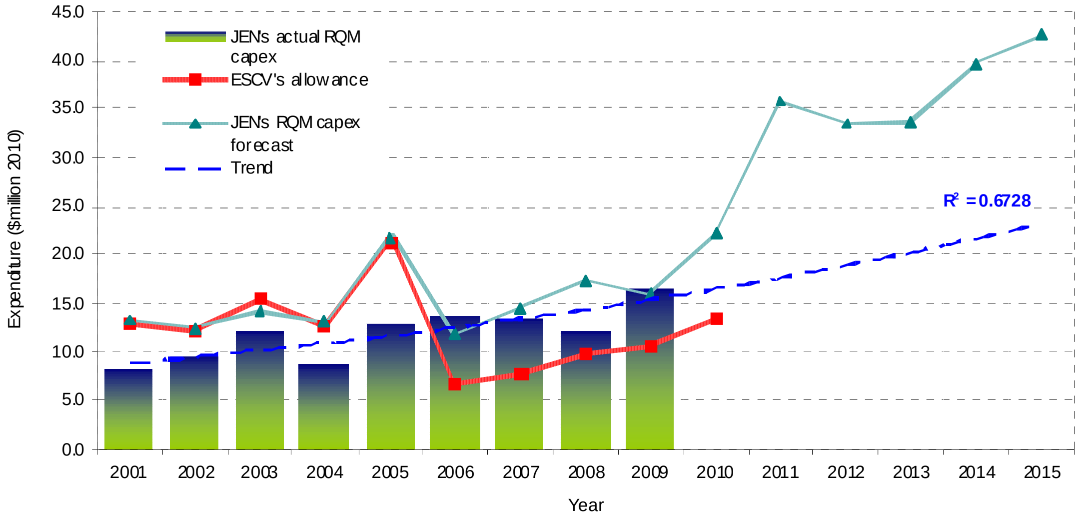
Figure P.2 Powercor's RQM capex—historical and proposed ($'m, 2010)



Source: RIN templates, ESCV's EDPR 2006–10 and regulatory accounts.

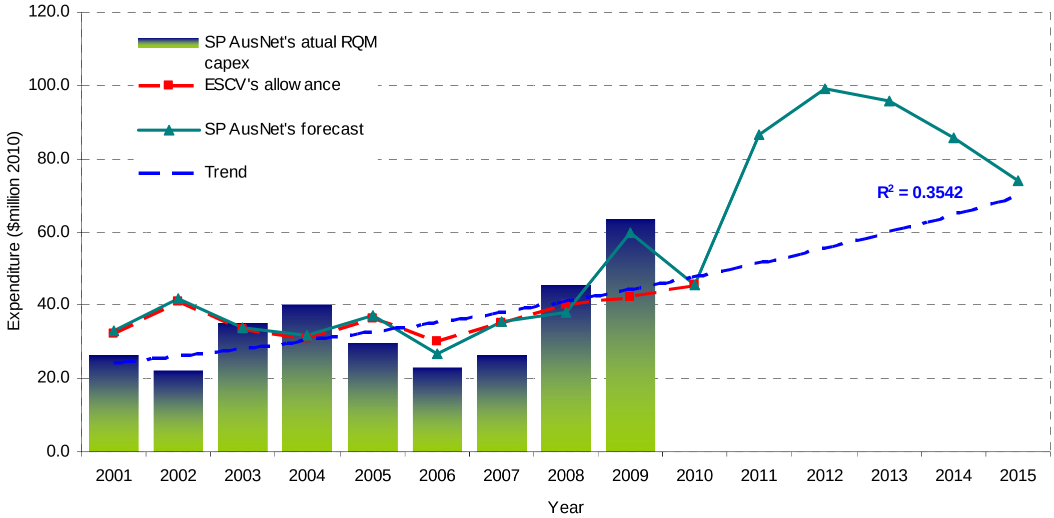
225 See section P.3.4.
226 See Figure P.3–Figure P.5 .

Figure P.3 JEN's RQM capex—historical and forecast ($’m, 2010)



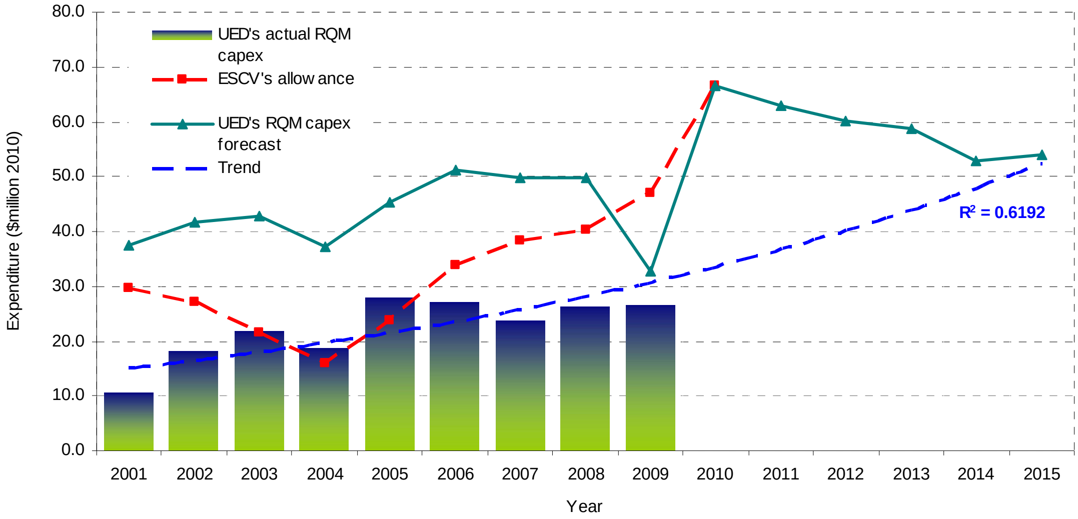
Source: RIN templates, ESCV's EDPR 2006–10 and regulatory accounts.

Figure P.4 SP AusNet's RQM capex—historical and proposed ($’m, 2010)



Source: RIN templates, ESCV's EDPR 2006–10 and regulatory accounts.

Figure P.5 United Energy's RQM capex—historical and proposed ($'m, 2010)



Source: RIN templates, ESCV's EDPR 2006–10 and regulatory accounts.

For this final decision, while the AER considers that 2009 data should be factored into the assessment process for replacement expenditure, 2010 data should be excluded as it will most likely not reflect actual expenditure for that period.

P.3.10.11CitiPower

Draft decision outcomes and revised regulatory proposal forecast

Following the adjustments detailed in Table P.8, the AER was satisfied that an estimate of $137.2 ($ 2010) million for CitiPower's forecast RQM capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered these adjustments were the minimum necessary for it to be satisfied that CitiPower's RQM capex forecast reasonably reflected the capex criteria.

CitiPower's revised regulatory proposal included a RQM capex proposal of $191.6 million ($2010) for the forthcoming regulatory control period. CitiPower's revised capex proposal is set out in Table P.9.

Table P.8 AER draft conclusion on RQM capex for CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	45.0	54.6	48.5	50.9	58.9	258.0
less function code adjustments						
Fault level mitigation project	13.4	14.5	14.3	15.2	14.4	71.7
HV Fuse Unit & Surge Divert. Repl.	0.2	0.2	0.2	0.1	0.1	0.8
HV and LV Switch replacement	2.5	2.5	2.2	2.0	1.7	11.0
Reliability	0.8	0.9	0.8	0.8	0.8	4.2
Services	1.2	1.1	0.9	0.8	0.7	4.7
Transformer replacement	0.2	0.1	0.1	0.0	0.0	0.3
Zone substation plant replacement	–1.6	– 4.1	–1.9	–2.6	4.4	2.5
ZSS - Secondary systems replacement	4.9	5.2	5.2	5.1	5.0	25.4
total adjustments	21.7	28.6	21.8	21.5	27.1	120.7
AER's draft decision	**23.3**	**26.0**	**26.7**	**29.5**	**31.8**	**137.2**

Source: AER, draft decision, July 2010, p. 355.

Table P.9 CitiPower's initial and revised RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Initial proposal	45.0	54.6	48.5	50.9	58.9	258.0
Revised proposal	34.3	37.1	37.7	40.3	42.2	191.6
Difference	**–10.7**	**–17.5**	**–10.8**	**–10.6**	**–16.7**	**-66.4**

Source: CitiPower, Regulatory proposal, RIN, November 2009, template 2.1; Revised regulatory proposal, RIN, July 2010, template 2.1.

Issues and AER considerations

Fault level mitigation project

CitiPower has revised its forecasts for this program downwards from $100 million ($ 2010) over 5 years to $7.2 million ($ 2010) for the forthcoming regulatory control period. The AER's draft decision rejected this program as it was considered to be alternative control services projects. Subsequently CitiPower's revised regulatory proposal has only included programs that are relevant to standard control services.

The AER notes Nuttall Consulting's reasoning in rejecting the revised forecast for this project.[227] The AER also noted the submission of the Property Council of Australia on

[227] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 73–76.

this issue.[228] Nuttall was not convinced that CitiPower had demonstrated that it would have an immediate or likely need to alter the nominated sub-stations within the forthcoming regulatory control period. The AER further reviewed the information provided by CitiPower and the Property Council of Australia and made further inquiries of CitiPower to clarify some details. CitiPower explained the forecast was based on known approaches by developers and building owners and extrapolation of that demand in the light of broader Government initiatives to promote building energy efficiency.

Taking into account CitiPower's response to the follow up information request and the Property Council of Australia submission the AER is satisfied that CitiPower's revised forecast is reasonable for this activity with regard to:

- how the numbers of project required has been determined and
- how the units costs have been derived.[229]

Based on this review, the AER accepts CitiPower's proposed forecast for the fault level mitigation program. The AER considers that CitiPower has reasonably demonstrated that this program reflects the capex criteria and the capex objectives, taking into account the capex factors.[230]

HV and LV Switch replacement: Nilsen LV air circuit breaker replacement

CitiPower's revised regulatory proposal forecast $16.5 million ($2010) in the forthcoming regulatory control period for high voltage and low voltage switch replacement. The AER's draft decision rejected CitiPower's initial proposal of $15 million ($2010) and recommended an allowance of $4.1 million ($2010).

CitiPower's revised regulatory proposal raised a number of issues regarding the AER assessment for this category, specifically the assessment for the Nilsen LV circuit breakers. CitiPower revised regulatory proposal stated:

- CitiPower does not consider that two failures in 2005 and 2007 can properly be considered as managing the risks.
- CitiPower notes that the Nilsen breakers are at least 40 years old and considers that the recent failures indicate the population is entering its “end-of life” phase, which can involve a rapid increase in the failure rate. As such, unless a prudent replacement program is established, more failure would be expected at an increasing rate.

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228 Property Council of Australia, *Submission to the AER: CitiPower's original regulatory proposal 2011-2015 for the fault level compliance service fee*, August 2010.

229 CitiPower, *Revised regulatory proposal*, pp. 293–298; PB, *Review of repex model*, p. 19; CitiPower, Email 10 September 2010 response to AER information request, CitiPower, Email 21 September 2010 response to AER information request. Refer to appendix for a full list of the attachments for these emails.

230 Capex factors (1), (2), (3) and (5) are particularly relevant to this analysis..

- CitiPower does not include RQM capex for 2006-08 for Nilsen circuit breakers, therefore historical expenditure would not provide sufficient expenditure for the forthcoming regulatory control period.

- Given the AER's draft decision allowance it would take another fifteen years to replace the entire population of Nilsen circuit breakers. This would make the last of these units in service around 60 years old and thus posing an unacceptable risk.

CitiPower has also provided a revised project template for the Nilsen circuit Having reviewed CitiPower's regulatory proposal and supporting information, AER maintains its draft decision position that CitiPower has not reasonably demonstrated that the increase in expenditure is prudent and efficient in accordance with the NER.

With respect to risks management due to ageing (including the recent failures), the draft decision acknowledged that the risks exist and a planned replacement program is required. However the AER's concerns related to a need for CitiPower to replace its entire population of Nilsen circuit breakers in the forthcoming regulatory control period. In this regard the AER noted the findings of the Statistics Directorate of the OECD:

> It is generally agreed that a group of fixed assets that are installed or constructed in a given year will not all be withdrawn from use at exactly the moment when they reach the end of the average working life for that particular kind of asset. In other words, the assumption of "simultaneous exit" is not realistic and retirements of assets will occur both before and after the average service life of the asset concerned. It is further agreed that the occurrence of retirements around the average service life will follow some kind of bell shaped curve; i.e. retirements will start slowly, accelerate to some modal retirement age and decelerate thereafter until they are all gone.[231]

CitiPower's revised regulatory proposal did not reasonably address why gradual replacement is not possible. The AER recognises CitiPower's concern that the Nilsen breaker population is demonstrating an increasing rate of failure and that these failures can have significant consequences. The AER however does not consider that the evidence supplied of the rate of failure is so severe as to warrant an immediate program for the retirement of all assets in the forthcoming regulatory control period. The failure of 2 units out of 107 units across a five year period is not persuasive evidence that all 97 remaining units are in imminent need of replacement. The AER has considered the bath-tub curve submitted by CitiPower but notes the submitted curve is generic in nature and is not calibrated in a meaningful way to the Nilsen circuit breaker population. Although the AER in the draft decision invited CitiPower to submit economic analysis to support its forecasts CitiPower has declined to do so.[232]

With regard to CitiPower's comments regarding the implication of the AER's draft decision, the AER notes that this analysis is an inaccurate representation of the facts. In contrast to CitiPower's comments, the repex model was forecasting a significant

[231] OECD, Statistics Directorate National Accounts Division, 1998. *Mortality functions for Estimating Capital Stocks*, Second Meeting of the Canberra Group on Capital Stock Statistics, Paris, September.
[232] CitiPower, *Revised regulatory proposal*, p. 305.

growth in expenditure in this category at a rate of approximately 10 per cent per annum. Based upon this rate of increase and CitiPower's proportion of replacement in the next period, all breakers would be replaced within approximately 12 years with the oldest being around 52 years old.[233]

Regarding the use of 2009 data, the AER accepts CitiPower's proposition that this data should be included in the AER's consideration. The AER notes that by including actual expenditure for 2009 in the calculation of the efficient base from which to increment the expenditure a substantially higher allowance will result relative to the draft decision. Combining the increased rate of asset replacement noted with the higher expenditure base will lead to a substantial increase in the rate of replacement for these circuit breakers. Essentially this will allow for CitiPower to replace approximately 40 per cent of its Nilsen circuit breakers replacements population in the forthcoming regulatory control period - with the remaining units being replaced before the end of the period that follows the next i.e. within 10 years.[234] The AER considers that this replacement profile is consistent with the replacement approach set out above and is a realistic program to replace these assets.

Accordingly, the AER rejects CitiPower's forecast as the AER considers that:

- CitiPower's regulatory proposals have not demonstrated a need to replace its entire population of LV Nilsen in the forthcoming regulatory control period
- CitiPower's regulatory proposals have not demonstrated that that the timing of the replacement was prudent and efficient.

Apart from this lack of evidence not supporting the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers), the AER also considers that the RPP are not satisfied. For example, in the absence of robust evidence it cannot be determined whether the costs that will be incurred are efficient such that CitiPower should have a reasonable opportunity to recover at least the efficient costs of complying with regulatory requirements (see s. 7A(2) of the NEL).

Accordingly the AER's conclusion, based on its repex model output, on CitiPower's RQM capex is set out in Table P.10.[235]

Reliability replacement

CitiPower's revised regulatory proposal forecast $4.5 million ($2010) in the forthcoming regulatory control period for reliability replacements. The AER's draft decision rejected CitiPower's initial proposal of $4.2 million ($2010) and recommended no allowance for these programs.

CitiPower's revised regulatory proposal requested the AER to reconsider its position on reliability replacement. CitiPower's revised regulatory proposal stated that it is

233 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 72.
234 ibid., p. 72.
235 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.

proposing a relatively modest expenditure to address small pockets of the network experiencing levels of reliability well below average levels. CitiPower also stated this program to be necessary to meet reasonable expectations of reliability of supply as required by clause 5.2 of the Distribution Code.

CitiPower revised regulatory proposal also included:

- commentary by PB on Nuttall analysis of this expenditure and the alignment of the expenditure with the repex model results[236]
- further details of the individual programs that made up the reliability expenditure.[237]

In assessing CitiPower's regulatory proposal and supporting information, the AER maintains its draft decision position that CitiPower has not reasonably demonstrated that the increase in expenditure is prudent and efficient in accordance with the NER.

Regarding the CitiPower's obligation under the Victorian Distribution Code the AER notes that this program was rejected by the ESCV in the current regulatory period as it was deemed to be reliability improvement programs. The AER has also reviewed these programs and notes that these all appear to be reliability improvement programs targeted at the worse served customers. As such, it is reasonable to consider that these programs would provide an incentive for CitiPower to improve its reliability standards.[238]

The AER recognises that the costs for these programs may outweigh the incentives under the STPIS. However, the AER considers that CitiPower would need to provide some analysis to justify the prudency and efficiency of the increase in capex expenditure. Despites the AER's comments in the draft decision this type of information has not been provided.[239] Regarding PB comments that the AER has not undertaken any fundamental analysis for this program to support its draft decision, the AER considers that the onus is on the DNSP to provide supporting analysis for the AER to review.[240] In the absence of adequate supporting analysis by the DNSP and its advisers the AER is in no position to assess the merits of such activity.

Apart from this lack of evidence not supporting the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers), the AER also considers that the RPP are not satisfied. For example, in the absence of robust evidence it cannot be determined whether the costs that will be incurred are efficient such that CitiPower should have a reasonable opportunity to recover at least the efficient costs of complying with regulatory requirements (see s. 7A(2) of the NEL).

236 Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, July 2010, p. 19.
237 CitiPower, Revised regulatory proposal, pp. 306–308
238 This is not in accordance with the clause 6.5.7 (c)1-3; Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 70; Essential Services Commission of Victoria, *Final Decision Volume 1*, *Electricity Distribution Price Review 2006-10*, October 2005, p. 297.
239 AER, *Draft decision*, p. 354
240 Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, July 2010, p. 19. Capex factor 3 is particularly relevant to this analysis.

Accordingly the AER's conclusion, based on its repex model output, on CitiPower's RQM capex is set out in Table P.10.[241]

Zone substation secondary systems replacement

CitiPower's revised regulatory proposal forecast $38.9 million ($2010) in the forthcoming regulatory control period for the replacement of secondary systems within the zone substations. The AER's draft decision rejected CitiPower's initial proposal of $29.1 million ($2010) and recommended an allowance of $3.7 million ($2010).[242]

CitiPower's revised regulatory proposal asserted that the AER did not consider the details provided by CitiPower in an email dated 26 February 2010. The AER notes that it has assessed this information in the draft decision and the relevant documents pertaining to this email were listed in footnote 137 on page 349 of the draft decision. CitiPower's revised regulatory raised several issues relating to:

- general comments regarding risks and the repex model. These issues were addressed in sections P.3.10.1 to P.3.10.10.
- specific comments regarding CitiPower's aged relay replacement program, other programs in this function code and the AER draft decision. These issues are discussed below.

On aged relays replacement, CitiPower's revised regulatory broadly stated:

- the increase in relay replacement in the forthcoming regulatory control period is driven by its RCM. The analysis has allocated very high overall risk score to those relays that CitiPower proposes to replace in the forthcoming regulatory control period.
- one type of relay can affect hundreds of circuits in CitiPower's networks, jeopardising the high reliability level of the network and affecting a large number of customers.

CitiPower's revised regulatory proposal also included details of the individual programs that made up the expenditure for this function code.[243]

Having reviewed the revised regulatory proposal, for the reasons set out in the following paragraphs, the AER maintains its position that CitiPower has not adequately demonstrated that its forecasts are reasonable. The AER notes Nuttall Consulting's concerns regarding the validity of the modelling that underpins CitiPower's forecast, both in terms of the estimation of end-of-life associated with the risk scores and the algorithm used to predict the changes in risk levels with time. Given the weakness of the supporting information provided by CitiPower, the AER does not consider that CitiPower has demonstrated that this particular program has

[241] In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis..

[242] The $7.2 million for the fault mitigation program has been removed from this function code and assessed in previous section.

[243] CitiPower, *Revised regulatory proposal*, pp. 301–304.

satisfied the capex criteria. That is, the AER is not satisfied that the risk scores allocated by CitiPower are a robust assessment based on objective criteria that took into account the condition of the relays.[244] Neither the original proposals nor the revised regulatory proposals identified any change to legislation, regulations or licence conditions that required CitiPower to change its approach to the management of replacement activity. No new service standards were introduced that would require a change of management practices. Furthermore no evidence was provided that CitiPower was facing any risk that it does not currently face.

Regarding CitiPower's other programs, the AER notes that CitiPower has provided some additional templates in its revised regulatory proposal to support its claims. However these templates are similar to those provided on 26 February 2010 and contain no meaningful new information. Having reviewed the revised regulatory proposal, the AER maintains its position that CitiPower has not adequately demonstrated that the proposed volume and associated expenditure is reasonable. The AER agrees with Nuttall Consulting that the paucity of information provided was inadequate to substantiate such a large increase in expenditure.[245]

In summary the AER considers that CitiPower's forecast are not reasonable estimates as it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification (cost benefit analysis including options analysis) – clauses 6.5.7(c)(1–3)

- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)

- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)

- has adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, CitiPower has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3)

- has not adequately demonstrated how its forecasts were a reflection of its Asset Management Plan, that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure – clauses 6.5.7(c)(1–3).

In addition, the AER notes that that CitiPower considers it is inappropriate to use the repex model to determine the allowance as many of its replacement programs are not

244 Given the lack of information the AER considers the AER was not able to form a view that the program was prudent and efficient. CitiPower, *Revised regulatory proposal*, pp. 299–301; CitiPower, *CP 156 - Ageing unreliable relay replacement*, July 2010, pp. 1–4; CitiPower, *Asset Management Plan - protection equipment relays*, December 2009.

245 The major difference being the inclusion of a high level risk analysis.

related to ageing factors. The AER acknowledges this view but, in the absence of any other more appropriate guidance, the AER agrees with Nuttall Consulting that the rate of increase suggested by the repex model can be considered the most reasonable guide. The AER however agree with CitiPower that 2009 data should be included into the AER's consideration. This year captures the commencement of a significant number of the ongoing programs, and so should better reflect CitiPower's ongoing needs. In addition, the growth rates of the repex model has been re-calibrated to allow for historical replacement volumes – this has resulted in increases in the expenditure growth rates from the base-line.

Accordingly the AER’s conclusion, based on its repex model outputs, on CitiPower's RQM capex is set out in Table P.10.[246]

AER conclusion

For the reasons outlined above, the AER considers the following adjustment is not satisfied that CitiPower's forecast RQM capex reasonably reflects the capex criteria, including the capex objectives. The AER agrees with Nuttall Consulting that the RQM allowance for CitiPower should be adjusted as follows:

Table P.10 AER conclusion on CitiPower's RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015
Proposed	34.3	37.1	37.7	40.3	42.2
less					
Moved to ESL[a]	–4.5	–4.7	–.6	–5.0	–5.1
Zone substation secondary replacement	–5.6	–5.6	–5.6	–5.5	–5.4
HV and LV Switch replacement	–2.5	–2.4	–2.1	–1.9	–1.5
Reliability replacement	–0.9	–0.9	–0.9	–0.9	–0.9
AER conclusion	**20.9**	**23.5**	**24.5**	**27.0**	**29.2**

(a) Includes poles, cross-arms and conductor replacement programs.

P.3.10.12Powercor

Draft decision outcomes and revised regulatory proposal forecast

Following the adjustments detailed in Table P.11 the AER was satisfied that an estimate of $256.4 million ($2010) for Powercor’s forecast RQM capex reasonably reflects the capex criteria, taking into account the capex factors. The AER considered that these adjustments were the minimum necessary for it to be satisfied that Powercor’s RQM capex forecast reasonably reflect the capex criteria.

246 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.

Powercor's revised regulatory proposal included a RQM capex proposal of $364.4 million ($2010) for the forthcoming regulatory control period. Powercor's revised capex proposal is set out in Table P.12.

Table P.11 AER draft conclusion on RQM capex for Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	72.2	71.8	74.1	73.1	73.2	364.4
less function code adjustments						
HV Switch Replacement	0.7	0.7	0.7	0.7	0.7	3.5
OH/UG line replacement	0.6	0.5	0.4	0.2	0.0	1.8
Reliability improvement	1.5	1.5	1.5	1.5	1.5	7.5
ZSS - plant replacement	3.5	2.9	3.9	2.1	1.8	14.2
ZSS - secondary systems replacement	4.1	3.9	3.7	3.6	3.4	18.8
Conductor	12.1	12.2	12.6	12.7	12.7	62.3
total adjustments	22.6	21.7	22.8	20.8	20.1	108.0
AER's draft decision	**49.6**	**50.2**	**51.3**	**52.2**	**53.1**	**256.4**

Source: AER draft decision, July 2010, p. 366.

Table P.12 Powercor's initial and revised RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Initial proposal	72.2	71.8	74.1	73.1	73.2	364.4
Revised proposal	71.3	76.9	75.3	70.5	70.4	364.4
Difference	**–0.9**	**5.1**	**1.2**	**–2.6**	**–2.8**	**0.0**

Source: Powercor, Regulatory proposal, November 2009, template 2.1; Revised regulatory proposal, RIN, July 2010, template 2.1.

Issues and AER consideration

General comments

The AER has reviewed the SKM report submitted by Powercor and notes the advice put forward by SKM.[247] Although the report highlights that Powercor may need an additional opex allowance, as a result of the AER reduction to Powercor's capex allowance, the AER notes that Powercor's regulatory proposals have not put forward any potential opex savings should all of its the capex allowance be approved. Notwithstanding this, the AER notes that Powercor has not included SKM's

[247] Sinclair Knight Merz, *Impact of ageing assets on Powercor operating costs*, July 2010

recommendations in its revised regulatory proposal in the form of an increase to its opex allowance.[248]

Conductor replacement

Given the findings of the Victorian Bushfire Royal Commission, the AER considers that there is a considerable safety case for this program and has assessed it as part of the Environmental, Safety and Legal capex category in section P.4.1.2.

Zone substation plant replacement

Powercor's revised regulatory proposal forecast $49.4 million ($2010) in the forthcoming regulatory control period for the replacement of zone substation plant equipment. The AER's draft decision rejected Powercor's initial proposal of $34.6 million ($2010) and recommended an allowance of $20.4 million ($2010).

Powercor's revised regulatory proposal included several claims that the AER was in error by:

- rejecting the Condition Based Replacement Model (CBRM) forecast but has accepted a similar forecast by Energex using CBRM
- rejecting the CBRM assumptions while its consultants considered them to be relevant.[249]

Powercor's revised regulatory proposal also further details of the individual zone substation that make up the zone substation plant replacement expenditure. Powercor also commissioned EA Technology to review Nuttall Consulting's assessments of it forecasting model the CBRM.[250]

As noted earlier, the general issues relating to the AER's repex model and assessment process has been discussed in sections P.3.10.1 and P.3.10.10. Specific discussion regarding this asset category is discussed below.

As outlined in the draft decision the AER had the following concerns:

- With respect to the inputs for transformers—concerns regarding the disparity between the degree of polymerisation and the resulting output of the CBRM.
- With respect to the assumptions for transformers—concerns regarding Powercor's use of an international failure probability rate that was inconsistent with its own historical data.
- With respect to circuit breakers—concerns regarding the assets life assumption and its effects on the outputs.

[248] Powercor, *Revised regulatory proposal*, pp. 280–281.
[249] Powercor, *Revised regulatory proposal*, pp. 283–287.
[250] EA Technology, *Review of draft determination*, July 2010.

- With respect to the assumptions for circuit breakers—concerns regarding Powercor's use of an international failure probability rate that was inconsistent with its own historical data.[251]

The AER's draft decision also highlighted the information that the Powercor will need to address the AER concerns. The draft decision stated:

> this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that the number of failures, probability of failure, the ageing relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account Powercor’s historical information, including failure statistics, asset condition monitoring results and risk mitigation measures.[252]

In assessing Powercor's regulatory proposals and the supporting information, the AER maintains its draft decision position that Powercor has not reasonably demonstrated that the increase in expenditure is prudent and efficient in accordance with the NER.

With respect to Powercor's point that the AER has accepted Energex forecasting model—the CBRM— the AER considers that the assumption, application and circumstances of Energex were mutually exclusive from Powercor.

- With respect to Powercor's response via EA Technology, while several claims were made about the CBRM, neither EA Technology nor Powercor addressed why it would be prudent and efficient for Powercor to replace the stipulated zone substation transformers in the forthcoming regulatory control period when Powercor's transformer condition assessment indicated that some of these transformers were still in reasonable condition.[253] The AER's draft decision also noted that Powercor's Asset Management plans also indicated that replacement will only occur as a result of an unsatisfactory condition assessment.

- With respect to the probability of failure, the AER notes that EA considers these failure rates to be appropriate. However, while these failure rates may be an appropriate benchmark for general planning purposes, the AER maintains that these failure rates do not reflect Powercor's own circumstances.[254] The AER notes that benchmark lives and failure rates are a starting point in an analysis where no records exist as to the observed in service condition and failure rate of an item of plant. Powercor though specifically references its own asset management plans and condition based assessments as a basis for its forecasts. The AER considers that a prudent DNSP will have reliable records in this regard and therefore will not need to rely on generic estimates that are not specific to their own circumstances.

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251 AER, *Draft decision*, pp. 359–360.
252 ibid., p. 360.
253 As summarised in section P.3.5, EA technology stated that the outputs of the CBRM (health index) indicated a need to replace several transformers in the forthcoming regulatory control period. As noted in the draft decision, the condition test of these transformers stated otherwise. AER, *Draft decision*, p. 359.
254 EA Technology, *Review of draft determination*, July 2010. p. 2; Powercor, *Revised regulatory proposal*, pp. 283–287.

Powercor's revised regulatory proposal also included additional expenditure of $14.4 million ($2010) to rebuild the Sunshine zone substation. The AER has reviewed the information provided and has taken Nuttall Consulting's advice into consideration. Apart from the EA Technology report and certain other commentary, Powercor's revised regulatory proposal did not include any detailed analysis that addressed the draft decision concerns. Based on the information on hand, the AER agrees that there is a need for the replacement. The AER however, considers that Powercor has not justified why the allowance provided for in the draft decision would be inadequate to address this need.[255]

Apart from this lack of evidence not supporting the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers), the AER also considers that the RPP are not satisfied. For example, in the absence of robust evidence it cannot be determined whether the costs that will be incurred are efficient such that Powercor should have a reasonable opportunity to recover at least the efficient costs of complying with regulatory requirements (see s. 7A(2) of the NEL).

The AER, however, has reviewed, and agrees with, Nuttall Consulting's assessment that the allowance provided in the draft decision may be insufficient to capture all assets categories for zone substation replacement. In the AER's experience an allowance for sundry costs in a capital project would lie in the range of 0 to 30 per cent. Nuttall Consulting has recommended the mid point of this range taking into account the level of detail contained in the estimates of Powercor. This selection appears to be reasonable to the AER. The AER therefore considers that a contingency allowance of 15 per cent will address this issue.[256] In addition to this, the repex model has been recalibrated to reflect 2009 expenditure and this has raised the allowance for this function code significantly.
Accordingly, the AER’s conclusion on Powercor's RQM capex is set out in Table P.13.[257]

Zone substation secondary systems replacement

Powercor's revised regulatory proposal forecast $30.6 million ($2010) in the forthcoming regulatory control period for the replacement of secondary systems within the zone substations. The AER's draft decision rejected Powercor's initial proposal of $30.8 million ($2010) and recommended an allowance of $12 million ($2010).

Powercor's revised regulatory proposal asserted that the AER did not consider the details provided by Powercor in an email dated 26 February 2010. The AER rejects this assertion. The AER had reviewed and considered all information provided to it as part of the determination process. The relevant documents pertaining to this email were reviewed by the AER and listed in footnote 179-181 on page 361 of the draft decision. Powercor's revised regulatory raised several issues relating to:

255 Powercor, *PAL - SU Rebuild material program*, August 2010, pp. 1–3.
256 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 142.
257 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.

- general comments regarding risks and the repex model. These issues were addressed in Sections P.3.10.1 and P.3.10.10

- specific comments regarding Powercor's aged relay replacement program, other programs in this function code and the AER draft decision. These issues are discussed below.

On aged relays replacement, which is the largest component of this category, Powercor's revised regulatory broadly stated:

- the increase in relay replacement in the forthcoming regulatory control period is driven by its RCM. The analysis has allocated very high overall risk score to those relays that Powercor proposes to replace in the forthcoming regulatory control period.

- one type of relay can affect hundreds of circuits in Powercor's networks, jeopardising the high reliability level of the network and affecting a large number of customers.[258]

Powercor's revised regulatory proposal also included:

- details of the individual programs that made up the expenditure for this function code and

- materials programs templates that further details its forecasts.[259]

On aged relays replacement, having reviewed the revised regulatory proposal the AER maintains its position that Powercor has not adequately demonstrated that its forecast is reasonable. The AER notes Nuttall Consulting concerns regarding the validity of the modelling that underpins Powercor's forecast, both in terms of the estimation of end-of-life associated with the risk scores and the algorithm used to predict the changes in risk levels with time. For example as noted earlier Powercor stated that:

> the increase in relay replacement in the forthcoming regulatory control period is driven by its RCM. The analysis has allocated very high overall risk score to those relays that Powercor proposes to replace in the forthcoming regulatory control period.

However it was not apparent or adequately addressed in Powercor's proposals, that the assumptions (end of life of the aged-relays) or calculation used (algorithm used) to formulate these risks scores were appropriate. The AER is not satisfied that the risk scores allocated by Powercor are a robust assessment based on objective criteria that took into account the condition of the relays.[260] Neither the original proposals nor the

[258] Powercor, *Revised regulatory proposal*, pp. 287–294.

[259] Powercor, *Revised regulatory proposal*, pp. 291–294; Powercor, *PAL 156 - Ageing Unreliable Relay Replacement, PAL 156 - Augmentation Associated with SPAusNet Projects, PAL 156 - Communications Network Equipment Replacements, PAL 156 - Duplicate Protection on Tied 66 kV Lines, PAL 156 - Replacement Battery Banks and Chargers, PAL 156 - Replacement of Supervisory Cable with Existing OFC*, pp. 1–2.

[260] Given the lack of information the AER was not able to form a view that the program was prudent and efficient. Powercor, *Revised regulatory proposal*, pp. 287–297; Powercor, *PAL 156 - Ageing*

revised regulatory proposals identified any change to legislation, regulations or licence conditions that required Powercor to change its approach to the management of replacement activity. No new service standards were introduced that would require a change of management practices. Furthermore no evidence was provided that Powercor was facing any risk that it does not currently face.

Regarding Powercor's other programs, the AER notes that Powercor has provided some additional templates in its revised regulatory proposal to support its claims. However the templates provided were similar to those provided on 26 February 2010 and contained no meaningful new information.[261] That is, these templates contained no detailed analysis that would support Powercor's views for such as large step change in expenditure.

In summary the AER considers that Powercor forecasts are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification (cost benefit analysis including options analysis) – clauses 6.5.7(c)(1–3)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)
- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Powercor has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3)
- has not adequately demonstrated how its forecasts were a reflection of its Asset Management Plan, that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure – clause6.5.7(c)(1–3).

In addition, the AER notes that that Powercor considers it is inappropriate to use the repex model to determine the allowance as many of its replacement programs are not related to ageing factors. The AER acknowledges this view but, in the absence of any other more appropriate guidance, the AER agrees with Nuttall Consulting that the rate of increase suggested by the repex model can be considered the most reasonable guide.[262] The AER however agrees with Powercor that 2009 data should be included into the AER's consideration. This year captures the commencement of a significant number of the ongoing programs, and so should better reflect Powercor's ongoing

unreliable relay replacement, July 2010, pp. 1–4; Powercor, *Asset Management Plan - protection equipment relays*, November 2009.

261 The notable differences were the inclusion of a high level risk analysis to these templates.

262 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 145.

needs. In addition, the growth rates of the repex model has been re-calibrated to allow for historical replacement volumes – this has resulted in increases in the expenditure growth rates from the base-line.[263]

Accordingly the AER’s conclusion, based on its repex model outputs, on Powercor's RQM capex is set out in Table P.13.[264]

Reliability replacement

Powercor's revised regulatory proposal forecast $9.2 million ($2010) in the forthcoming regulatory control period for reliability replacements. The AER's draft decision rejected Powercor's initial proposal of $7.5 million ($2010) and recommended no allowance for these programs.

Powercor's revised regulatory proposal requested the AER to reconsider its position on reliability replacement. Powercor's revised regulatory proposal stated that it is proposing a relatively modest expenditure to address small pockets of the network experiencing levels of reliability well below average levels. Powercor also stated this program to be necessary to meet reasonable expectations of reliability of supply as required by clause 5.2 of the Distribution Code.

Powercor's revised regulatory proposal also included:

- commentary by PB on Nuttall analysis of this expenditure and the alignment of the expenditure with the repex model results[265]
- further details of the individual programs that made up the reliability expenditure.[266]

The AER has reviewed the information provided by Powercor and considered the proposition in its revised regulatory proposal. The AER maintains its draft decision position that Powercor has not reasonably demonstrated that the increase in expenditure is prudent and efficient in accordance with the NER.

Regarding the Powercor's obligation under the Victorian Distribution Code the AER notes that this program was rejected by the ESCV in the current regulatory period as it was deemed to be reliability improvement programs. The AER has also reviewed these programs and notes that these all appear to be reliability improvement programs targeted at the worse served customers. As such, it is reasonable to consider that these programs would provide an incentive for Powercor to improve its reliability standards.[267]

The AER notes Nuttall Consulting's comments that the costs for the program may outweigh the incentives under the STPIS. However, the AER considers that Powercor

263 ibid., p. 145.
264 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.
265 Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, July 2010, p. 23.
266 Powercor, *Revised regulatory proposal*, pp. 294–296.
267 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 148–149.; Essential Services Commission of Victoria, *Final Decision Volume 1, Electricity Distribution Price Review 2006-10*, October 2005, p. 297.

would need to provide some analysis to justify the prudency and efficiency of the increase in capex expenditure. Despites the AER's comments in the draft decision this type of information has not been provided.[268] Regarding PB comments that the AER has not taken any fundamental analysis for this program to support its draft decision, the AER considers that the onus is on Powercor to provide supporting analysis for the AER to review.[269] In the absence of adequate supporting analysis by the DNSP and its advisers the AER is in no position to speculate on the merits of such activity.

In summary the AER considers that Powercor's forecasts are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification (cost benefit analysis including options analysis) – clauses 6.5.7(c)(1–3)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)
- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Powercor has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3)
- has not adequately demonstrated how its forecasts were a reflection of its Asset Management Plan, that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure – clauses 6.5.7(c)(1–3).

Accordingly the AER’s conclusion, based on its repex model outputs, on Powercor's RQM capex is set out in Table P.13.[270]

AER conclusion

For the reasons outlined above, the AER is not satisfied that Powercor's forecast RQM capex reasonably reflects the capex criteria, including the capex objectives. The AER agrees with Nuttall Consulting that the RQM allowance for Powercor should be adjusted as follows:

268 AER, *Draft decision*, p. 365.

269 Parsons Brinkerhoff, *Repex model Review: CitiPower - Powercor*, July 2010, p. 23. Capex factor 3 is particularly relevant to this analysis.

270 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4) and (5) are particularly relevant to this analysis.

Table P.13 AER conclusion on Powercor's RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015
Proposed	71.3	76.9	75.3	70.5	70.4
less					
Moved to ESL[a]	–36.4	–37.0	–37.8	–38.1	–38.3
Zone substation secondary replacement	–3.4	–3.2	–2.9	–2.7	–2.4
Zone substation plant replacement	–5.0	–9.8	–7.0	–1.5	–0.8
Reliability replacement	–1.8	–1.8	–1.8	–1.8	–1.8
AER Conclusion	**24.6**	**25.1**	**25.7**	**26.4**	**27.1**

(a) Includes poles, cross-arms and conductor replacement programs

P.3.10.13 Jemena Electricity Networks

Draft decision outcomes and revised regulatory proposal forecast

Following the adjustments detailed in Table P.1 the AER was satisfied that an estimate of $66.5 million ($2010) for JEN’s forecast RQM capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered these adjustments were the minimum necessary for it to be satisfied that JEN’s RQM capex forecast reasonably reflects the capex criteria.

JEN's revised regulatory proposal included a RQM capex proposal of $132 million ($2010) for the forthcoming regulatory control period. JEN's revised capex proposal is set out in Table P.15.

Table P.14 AER draft conclusion on RQM capex for JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	30.4	27.9	27.5	31.9	33.8	151.5
less function code adjustments						
Poles	1.6	2.4	3.0	3.3	3.4	13.8
Pole top structure	2.9	4.2	4.9	5.6	6.3	24.0
Conductors	4.6	2.5	2.1	2.4	3.2	14.8
Distribution transformers	0.1	–0.1	–0.1	–0.3	0.1	–0.2
Underground cables	0.3	0.3	0.7	1.3	1.5	4.1
Zone substation	5.0	3.8	3.1	4.6	4.6	21.1
Protection	0.4	–0.2	–0.3	0.8	0.0	0.6
Distribution switchgears	2.1	0.9	0.1	–0.1	–0.1	2.8
Reliability maintained (performance)	1.0	0.8	0.7	0.7	0.7	4.0
total adjustments	18.1	14.7	14.3	18.4	19.5	85.0
AER's draft decision	**12.3**	**13.2**	**13.2**	**13.5**	**14.3**	**66.5**

Source: AER draft decision, July 2010, p. 379.

Table P.15 JEN's initial and revised RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Initial proposal	30.4	27.9	27.5	31.9	33.8	151.5
Revised proposal	22.8	22.1	24.5	28.7	33.9	132.0
Difference	**-7.6**	**-5.8**	**-3**	**-3.2**	**0.1**	**-19.5**

Source: JEN, Regulatory proposal, November 2009, template 2.1; Revised regulatory proposal, RIN, July 2010, template 2.1.

Issues and AER consideration

Distribution transformers

JEN's revised regulatory proposal forecast $2.1 million ($2010) in the forthcoming regulatory control period for the replacement of distribution transformer. As indicated in AER's draft decision, JEN's forecast for this function code composed of two main components: an age/condition based component that was in line with the historical trend and a performance component that appeared to indicate a significant increase in expenditure. The draft decision accepted the age/condition based forecast, but rejected the performance component due to the deficiency of information.

JEN's stated in its revised regulatory proposal that it had extended its distribution transformer augmentation program by 1 year to reduce overall capex requirement.[271] Apart from this statement JEN did not submit any other information.

As discussed in section P.2.5.4 the AER has reduced JEN's proposed proactive distribution transformer upgrade program in the reinforcement capex. As the AER has accepted JEN's initial proposal, the AER considers it reasonable to allow for the additional expenditure based upon the average historical level between 2006 and 2009, escalated by the growth rates suggested by the repex model. This has resulted in a small increase above the amount proposed by JEN.

Accordingly the AER's conclusion, based on its repex model outputs, on JEN's RQM capex is set out in Table P.16.[272]

Zone substation plant replacement

JEN's revised regulatory proposal forecast $16.7 million ($2010) in the forthcoming regulatory control period for the replacement of zone substations plant equipment. The AER's draft decision rejected JEN's initial proposal of $29.4 million ($2010) for this function code and recommended an allowance of $8.3 million ($2010).

The AER has reviewed and considered all information provided to it as part of the determination process. The AER notes that JEN's revised regulatory proposal has sought to address some of the concerns raised by the AER in the draft decision.

Regarding the AER concerns about the impacts of reliability on customers, JEN's revised regulatory proposals included additional information that quantified these potential impacts. On JEN's assumptions regarding the potential impact of climate change on its network the AER does not agree with this view. The AER considers that climate change effects are a continual, progressive effect that have been and will continue to occur over time. The impact of past climate related events will already be reflected in historical expenditure whilst future capital requirements should be reflected in changed industry design and operational standards for plant and equipment. The AER does not consider a prudent business should speculatively incur costs to change design standards on an ad-hoc basis. As the AER has had regard to historical expenditure in formulating this allowance the AER considers that no further allowance should be made. The AER maintains the position as stated chapter 8 of this final decision for the reasons set out therein.

In addition to this, the AER has reviewed and considered the materials to support this impact on customers – one of the bases for this calculation being climate change – and considers that there was insufficient justification for the model inputs that generated the conclusion. The AER also considers that JEN would need to provide and justify its

271 JEN's, *Revised regulatory proposal: A08.1 - JENs reference to AER's concerns capex*, July 2010, p. 36.

272 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.

reliability models/assumptions to substantiate that such a significant increase in expenditure should occur in the forthcoming regulatory control period.[273]

Regarding the AER's concern about the timing of JEN's zone substation transformer replacement program, JEN's revised regulatory proposal indicated that it has decided to defer the replacement of FF zone transformers as a result of new test results. The AER notes that JEN's revised forecast for zone substation is now similar to the AER's repex model forecast for the draft decision.[274]

With respect to the AER's concerns about JEN's high level risk analysis for circuit breakers, JEN's revised regulatory proposal included additional qualitative risk commentary about the potential risks. The AER has reviewed this information and agrees with Nuttall Consulting that there was insufficient justification:

- on how JEN determined risks
- how this risk will change in the forthcoming regulatory control period
- how the change in risk will lead to the significant increase in replacement expenditure.[275]

Given the above the AER considers that JEN's forecasts are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

- has not demonstrated an underlying need for a step increase in investment – clauses 6.5.7(c)(1–3)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)
- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, JEN has not established a

273 Assumptions in the following AMPs: JEN, *Asset strategy strategic planning paper - JEN- zone substation circuit breaker replacement program*, November 2010, p. 17; JEN, *Asset strategy strategic planning paper - JEN - zone substation transformer replacements*, November 2010, p. 13. The calculation potential impact of 11.1 minutes to customers was based on historical failure rates of 11.1% for a transformer that is due for replacement, and 1% for a transformer in good condition, and 34.3% for failure of an associated 66kVline. For circuit breakers, JEN assumed that a failure of a 22kV circuit breaker may result in the loss of a distribution feeder for about 60 minutes. If the circuit breaker is in the bus tie position, the failure may impact the entire customer supply. If replacements are made to maintain expenditure levels at the average of the 2006-2009 period, and taking into account the different impacts of a failed bus tie circuit breaker and a 22kV distribution feeder circuit breaker, the SAIDI impact is 8.3 minutes.

274 JEN, *Revised regulatory proposal*, p. 163.

275 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 115.

clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3).

Having said all this, the AER, however, agrees with Nuttall Consulting that the allowance provided in the draft decision may be insufficient to capture all assets categories for zone substation replacement. The AER notes that that JEN has not replaced any transformers in the current regulatory period. Accordingly, the historical data would not reflect an allowance for this necessary expenditure. In the AER's experience an allowance for sundry costs in a capital project would lie in the range of 0 to 30 per cent. Nuttall Consulting has recommended the mid point of this range taking into account the level of detail contained in the estimates of JEN. This selection appears to be reasonable to the AER. The AER has adjusted its allowance accordingly. In addition to this the additional adjustment, the repex model has been recalibrated to reflect 2009 expenditure and this has raised the allowance for this function code significantly. [276]

Accordingly, the AER’s conclusion on JEN's RQM capex is set out in Table P.16.[277]

Protection

JEN's revised regulatory proposal forecast $7.3 million ($2010) in the forthcoming regulatory control period for protection replacements.[278] Although not indicated in AER's draft decision, JEN's forecast for this function code composed of two main components: an age/condition based component that was in line with the historical trend and a performance component that appeared to indicate a significant increase in expenditure. The draft decision accepted the age/condition based forecast, but rejected the performance component due to the deficiency of information.[279]

JEN's revised regulatory proposal did not discuss protection replacement.

Having assessed JEN's revised regulatory proposal, the AER accepts JEN's forecast for this category which included 2009 data. The AER considers it reasonable to allow for the expenditure based upon the average historical level between 2006 and 2009, escalated by the growth rates suggested by the repex model. However for consistency purposes, the AER agrees with Nuttall Consulting that this category should be assessed as a composite of the protection and reliability categories.

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276 ibid., p. 116.

277 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4) and (5) are particularly relevant to this analysis.

278 During the time of the draft decision, the AER issued the Victorian DNSPs with a new set of templates to report capex that were different to the RIN submitted as part of JEN's initial proposal. As JEN's initial proposal was based on the initial RIN, certain reliability programs were also allocated to this category. Nuttall Consulting's assessment of the initial proposal was based on the initial RIN. For the revised regulatory proposal the reliability components has been allocated to the reliability category. Email from JEN to AER dated 23 September 2010 in relation to AER request for information dated 17 September 2010.

279 The adjustment to JEN's allowance for this category in the draft decision was to remove the performance component.

Reliability

JEN's revised regulatory proposal forecast $36.3[280] million ($2010) in the forthcoming regulatory control period for reliability and performance replacements.

However, as a result of the ESV's recommendation, a large proportion of the expenditure for this category has been moved to Environmental Safety and Legal section.[281]

JEN's revised regulatory proposal raised several issues for consideration including:

- JEN is concerned that the AER has not accepted climate change impacts, particularly more violent and frequent wind and lightning storms. JEN also believes that, in order to maintain its forecast SAIDI, SAIFI, MAIFI and public safety levels, further capex will be required over the forthcoming regulatory control period to constrain the impact of an ageing network and to address the network impact of the forecast increase in frequency in violent storms due to climate change.

- JEN also indicated that it is facing a rising trend of asset failures. The trend in the numbers of high voltage equipment failures is increasing at the rate of 3.7 per cent per annum.

JEN stated that the investment in reliability projects to maintain performance in the face of increasing asset failures cannot be continued as:

- asset failures, especially overhead and zone substation assets, increase the health and safety risk to JEN’s employees as well the general public

- reactive replacement on failure is more costly, with explosive asset failure likely to increase the damage to other nearby assets

- cost effective reliability maintained projects are being exhausted.

JEN proposed a step-up in asset replacement expenditure in the forthcoming regulatory control period to:

- implement automatic switching using ACRs

- install remote control switching & monitoring equipment in distribution RMUs & kiosk substation – URDs

- install remote monitoring fault indicators – high voltage distribution feeders.

JEN believed that these additional projects are forecast to provide reliability benefits of five SAIDI minutes over five years, providing a baseline improvement that can be used to mitigate against increasing weather impact on reliability performance.[282]

280 Includes forecast for protection of $7.3 million

281 The ESV's considered the drivers for JEN's bushfire mitigation and HV ABC cables replacements to be safety related.

JEN's revised regulatory proposal also included several strategic planning papers on its power quality programs, automatic circuit recloser and remote control gas switches program and reactive fault mitigation program.

The AER has reviewed the information provided by JEN and considered the proposition in its revised regulatory proposal. The AER maintains its draft decision position that JEN has not reasonably demonstrated that the increase in expenditure is prudent and efficient in accordance with the NER.

Given the significant increase in expenditure in the forthcoming regulatory control period, the AER considers that JEN would need to provide detailed reliability and economic analysis to justify its proposal. The AER also notes that one of the drivers to these programs appear to be climate change. On JEN's assumptions regarding the potential impact of climate change on its network, the AER does not agree with this view. The AER considers that climate change effects are a continual, progressive effect that have been and will continue to occur over time. The impact of past climate related events will already be reflected in historical expenditure whilst future capital requirements should be reflected in changed industry design and operational standards for plant and equipment. The AER does not consider a prudent business should speculatively incur costs to change design standards on an ad hoc basis.

Regarding the power quality component of this category, the AER has considered the information in JEN's power quality strategic planning paper. The AER does not consider that this paper adequately justifies the scale of the increase in expenditure or the timing of the programs, particularly in the context of how JEN has managed these matters in the current period. That is, the information provided by JEN lacked the detailed analysis that shows how JEN has identified and profiled its quality of supply projects. As JEN is suggesting that compliance issues presently exist and it is only proposing to address a proportion of these, it appears reasonable to consider that it can manage these risks with expenditure that is in line with the historical trend.[283]

Further the AER considers that the overall increase in JEN's capex allowance in this final decision (from the draft decision) will be more than adequate to allow JEN to undertake significant works to address its reliability issues.[284]

Given the above the AER considers that JEN's forecast are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

- has not demonstrated an underlying need for a step increase in investment – clauses 6.5.7(c)(1–3)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)

282 JEN, *Revised regulatory proposal*, pp. 160–163.
283 Nuttall Consulting, Victorian Electricity Distribution Revenue Review, October 2010, pp. 118–119; JEN, *Strategic Planning Paper - Power Quality*
284 ibid., pp. 118–119.

- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, JEN has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3).

Accordingly the AER's conclusion, based on its repex model outputs, on JEN's RQM capex is set out in Table P.16.[285]

Underground cables

JEN's revised regulatory proposal forecast $7.3 million ($2010) in the forthcoming regulatory control period for the replacement of underground cables. The AER's draft decision rejected JEN's initial proposal of $7.6 million ($2010) for this function code and recommended an allowance of $3.4 million ($2010).

JEN's revised regulatory proposal included a strategic planning paper for underground cable replacement and PB's assessment of JEN's underground replacement program. These papers outlined several reasons for an increase in expenditure including:

- an increasing volume of assets in the 'wear-out' phase

- an increasing trend in the number of cable faults

- specific cable integrity issues including a volume of cable older than 70 years that has indications that the cable has reached the end of its operational life

- increasing risk resulting from changing weather patterns and operation of the incentive scheme

- a historical replacement rate that is significantly below the required long-term replacement rate.[286]

The AER has reviewed the information provided by JEN and considered the proposition in its revised regulatory proposal. Regarding JEN's proposition on assets entering the wear out phase, the increasing failure rates, the integrity issues, and the historical replacement rate, the AER notes that other than the PB replacement modelling, there is no other analysis to suggest that JEN's proposed increase in expenditure is prudent and efficient. Furthermore, while the AER acknowledges that there may be integrity issues associated with older cables, there was no detailed analysis within JEN's strategic plan to support this position [287]

Regarding the AER concerns about the impacts of reliability on customers, JEN's revised regulatory proposals included additional information that quantified these

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285 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4) and (5) are particularly relevant to this analysis.

286 JEN, *Revised regulatory proposal, Appendix 8.23 Strategic planning paper - Underground cables replacement,* July 2010, pp. 8–11.

287 ibid,. pp. 8–11.

potential impacts. On JEN's assumptions regarding the potential impact of climate change on its network the AER does not agree with this view. The AER considers that climate change effects are a continual, progressive effect that have been and will continue to occur over time. The impact of past climate related events will already be reflected in historical expenditure whilst future capital requirements should be reflected in changed industry design and operational standards for plant and equipment. The AER does not consider a prudent business should speculatively incur costs to change design standards on an ad-hoc basis. As the AER has had regard to historical expenditure in formulating this allowance the AER considers that no further allowance should be made. The AER maintains the position as stated in chapter 8 of this final decision for the reasons set out therein.

In addition to this, the AER has reviewed and considered the materials to support this impact on customers – one of the bases for this calculation being climate change – and considers that there was insufficient justification for the model inputs that generated the conclusion. The AER also considers that JEN would need to provide and justify its reliability models/assumptions to substantiate that such a significant increase in expenditure should occur in the forthcoming regulatory control period.[288]

With respect to JEN's replacement model output, and in particular, the lives it has assumed for this model, the AER notes does not consider these lives to be reasonable. In this regard the AER's notes PB's comment on this matter as:

> "appear to be typical of asset lives typically used by electricity distribution businesses in replacement modelling". [289]

The AER agrees with Nuttall Consulting that:

> there is no further clarification from PB on whether the comparative lives that PB refers to, used and validated by businesses that are current are seeing significant levels of replacement; or are these lives those that PB has historically used for replacement modelling.[290]

Furthermore, the AER also notes that this age does not fit with JEN's historical replacement profile. The AER notes that Nuttall Consulting has applied this life to the repex model and noted that JEN's historical replacement levels does not reflect this life. It should be further noted that Ofgem has found that the lives used by the Distribution Network Operators in the UK are well above 80 years for high voltage and low voltage cables.[291]

Given the above the AER considers that JEN's forecasts are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

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[288] JEN's stated that based on 2 failures of HV cables, affecting on average 2595 customers for approximately one hour, and no failures of LV cables, the impact of not proceeding with all of the replacements is an increase in SAIDI of 0.6 minutes. Costed at the value of consumer reliability, the associated cost is $0.3m.

[289] Parsons Brinckerhoff; *JEN Asset replacement volumes*, July 2010, p. 27.

[290] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 111

[291] ibid., p. 111.

- has not demonstrated an underlying need for a step increase in investment – clauses 6.5.7(c)(1–3)

- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)

- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, JEN has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3).

Accordingly the AER's conclusion, based on its repex model outputs, on JEN's RQM capex is set out in Table P.16.[292]

Distribution switchgear

JEN's revised regulatory proposal forecast $14.5 million ($2010) in the forthcoming regulatory control period for protection replacements. Although not indicated in AER's draft decision, JEN's forecast for this function code composed of two main components: an age/condition based component that was in line with the historical trend and a performance component that appeared to indicate a significant increase in expenditure. The draft decision accepted the age/condition based forecast, but rejected the performance component due to the deficiency of information.[293]

JEN's revised regulatory proposal provided an additional strategic planning paper which raised the following comments:

- an increasing volume of assets in the 'wear-out' phase

- asset inspections that show an increase in the volume of installations that are in unsatisfactory condition or of a non-preferred type

- a number of sub-categories of HV installations that are known to have specific defects that drive the need for replacement.[294]

In assessing JEN's regulatory proposal and the supporting information the AER maintains its draft decision position that JEN has not reasonably demonstrated that the increase in expenditure is prudent and efficient in accordance with the NER.

The AER notes JEN's proposition that a proportion of its assets are entering the wear out phase, however there is no analysis to suggest that JEN's assumptions on asset lives are reasonable–JEN considers the nominal life for both its kiosk and indoor

[292] In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4) and (5) are particularly relevant to this analysis.
[293] The adjustment was for the performance component of this function code.
[294] JEN, *Revised regulatory proposal, Appendix 8.23 Strategic planning paper - High voltage installation replacement program*, July 2010, pp. 8–11.

substation and high voltage overhead switch gear to be 35 years.[295] However, the AER notes that JEN's strategic plan acknowledges that:

> JEN does not currently have sufficient historical information to determine the exact relationship between asset age and condition i.e. the 'wear-out' age range is uncertain.[296]

The AER has considered this proposition and agrees with Nuttall Consulting that JEN has not presented any compelling evidence to support a replacement life of 35 years. In this regard the AER also notes that's this life (35 years) does not fit with JEN's historical replacement profile. The AER notes that Nuttall Consulting has applied this life to the repex model and noted that JEN's historical replacement levels does not reflect this life. The AER also notes that the benchmark lives for other DNSPs are well beyond 35 years.[297] It should be further noted that Ofgem has found that the lives used by the Distribution Network Operators in the UK are well above 35 years for distribution switchgear, other than pole mounted circuit breakers.[298]

The AER has also considered JEN's other statements concerning condition information and associated defects with certain of its distribution switchgear. This information was however high level in nature and does not demonstrate or quantify how why an increase in expenditure was required. For example JEN stated:

> For gang operated air break switches: This asset family is being targeted for replacement as there has been a fatality in the Victorian Electricity Supply Industry associated with a flashover of one of these units during operation. These switches are all approaching end of life and have limited and not well defined operating capabilities. Bird and animal strikes on this equipment are common and alignment and operational defects are common.[299]

However, JEN does not state how or why it currently accepts the same risks in the current period but does not consider it to be appropriate in the forthcoming regulatory control period.[300]

Furthermore several of safety related issues were raised to support the increase in expenditure for this program. The AER also notes that JEN had submitted this program to the Energy Safety Victoria for its consideration. The ESV has assessed this category in its review and did not consider that safety was the primary factor driving the need for replacement.[301]

Given the above the AER considers that JEN's forecasts are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

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295 ibid., p. 9.
296 ibid., p. 9.
297 CitiPower's and Powercor's response to repex modelling inputs dated 23 December 2010; SP AusNet response to repex modelling inputs dated 24 December 2010.
298 http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/May_doc_appx_results.xls
299 JEN, *Revised regulatory proposal, Appendix 8.23 Strategic planning paper - High voltage installation replacement program*, July 2010, p. 10.
300 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 112–113.
301 Energy Safe Victoria, *Assessment by Energy Safe Victoria of EDPR safety-related programs*, p. 20.

- has not demonstrated an underlying need for a step increase in investment – clauses 6.5.7(c)(1–3)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)
- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, JEN has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3).

Accordingly the AER's conclusion, based on its repex model outputs, on JEN's RQM capex is set out in Table P.16.[302]

Services

The AER's draft decision accepted JEN's forecast for this category. However for the revised regulatory proposal, JEN submitted its entire RQM capex forecast to the ESV for assessment. As a result of the ESV investigation, where the ESV has:

- accepted JEN's safety case, the AER has re-assessed these programs under environmental safety and legal category[303]
- rejected JEN's safety case, the AER has re-assessed this program under RQM.[304]

JEN's revised regulatory proposal did not respond to or disagree with the draft decision in relation to this category. Further, JEN's revised regulatory proposal did not include any new information for this category.

The AER has reassessed this category and for the reasons outlined in the draft decision the AER is satisfied that JEN's forecast for the RQM component of services forms part of a total forecast capex that reasonably reflects the capex criteria.

AER conclusion

For the reasons outlined above, , the AER is not satisfied that JEN's forecast RQM capex reasonably reflects the capex criteria, including the capex objectives. The AER agrees with Nuttall Consulting that the RQM allowance for JEN should be adjusted as follows:

[302] In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4) and (5) are particularly relevant to this analysis.
[303] For JEN's planned non-preferred service replacement and height replacement programs.
[304] For JEN's fault replacement services.

Table P.16 AER conclusion on JEN's RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015
Proposed	22.8	22.1	24.5	28.7	33.9
Less					
Moved to ESL[a]	–7.1	–8.6	–10.9	–12.5	–14.7
Distribution Transformers	0.4	0.5	0.5	0.7	0.2
Underground Cable	–0.1	–0.1	–0.7	–1.3	–1.4
Zone Substation	–0.6	–0.7	–1.1	–0.2	–1.0
Distribution Switchgear	0.2	–0.2	–0.7	–0.7	–0.7
Reliability maintained (performance)	–7.4	–4.6	–2.9	–4.1	–4.3
AER conclusion	**8.1**	**8.4**	**8.8**	**10.5**	**12.1**

(a) Includes all poles, pole top structures, conductor, fire mitigation and some services replacement programs.

P.3.10.14SP AusNet

Draft decision outcomes and revised regulatory proposal forecast

Following the adjustments detailed in Table P.17 the AER was satisfied that an estimate of $240.9 million for SP AusNet's forecast RQM capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered these adjustments were the minimum necessary for it to be satisfied that SP AusNet's RQM capex forecast reasonably reflects the capex criteria.

SP AusNet's revised regulatory proposal included a RQM capex proposal of $401.9 million ($2010) for the forthcoming regulatory control period. SP AusNet's revised capex proposal is set out in table P.18.

Table P.17 AER draft conclusion on RQM capex for SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	71.4	80.4	76.5	67.4	57.5	353.2
less function code adjustments						
OH line replacements	9.2	6.4	7.3	2.6	0.2	25.7
ZSS - plant replacement	13.8	25.2	17.4	14.0	5.8	76.2
Recoverable works	2.1	2.1	2.1	2.1	2.1	10.4
total adjustments	25.1	33.7	26.8	18.7	8.1	112.3
AER's draft decision	**46.4**	**46.7**	**49.7**	**48.7**	**49.4**	**240.9**

Source: AER draft decision, July 2010, p. 385.

Table P.18 SP AusNet's initial and revised RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Initial proposal	71.4	80.4	76.5	67.4	57.5	353.2
Revised proposal	71.4	85.5	75.9	76.7,	92.6	401.9
Difference	**0**	**5.1**	**-0.6**	**9.3**	**35.1**	**48.9**

Source: SP AusNet, Regulatory proposal, November 2009, template 2.1; Revised regulatory proposal, RIN, July 2010, template 2.1.

SP AusNet's revised regulatory proposal included additional expenditure for the replacement of:

- cross arms replacements $19 million
- EDO fuses $8 million
- bird and animal proofing $12.8 million
- enhanced control and electrical protection $11.3 million.[305]

As the primary drivers for these programs appear to be safety they have been considered in part 3 of this appendix under Environmental, Safety and Legal capex.

Issues and AER consideration

Zone substation plant

SP AusNet's revised regulatory proposal forecast $112.6 million ($2010) in the forthcoming regulatory control period for the replacement of zone substations plant and equipment. The AER's draft decision rejected SP AusNet's initial proposal for this function code and recommended an allowance of $76.2 million ($2010).

SP AusNet’s revised regulatory proposal raised several issues concerning the AER's assessment process in the draft decision including:

- the review process undertaken
- the use of the repex model
- views on the condition of transformers and circuit breakers
- view on the calibration of the models
- view on the allowance[306]

Regarding the review process SP AusNet contends that:

[305] All crossarms replacements have been moved to ESL.
[306] See section P.3.7.

- Nuttall Consulting and the AER resisted offers from SP AusNet to explain its model, and as such, the concerns raised about the model cannot be relied upon.

- all relevant information has not been reviewed by Nuttall Consulting and the AER.

SP AusNet revised regulatory proposal contained detailed technical analysis information on zone transformers replacements. [307]

The AER maintains that it has reviewed all information provided by SP AusNet but acknowledges that it had not referenced all documents it had taken into consideration in the draft decision.

Having reviewed the models and supporting information, the AER further considers that it has not misunderstood SP AusNet's forecasting model.

Regarding the use of the repex model SP AusNet contends that:

- the model fails to consider economic as opposed to technical considerations

- the lives suggested by the calibrated repex model are higher than those accepted by the AER in other determinations.[308]

Similar for other DNSPs, the AER's draft decision highlighted that the rationale for rejecting SP AusNet's proposal was based on the detailed review of the information provided, including asset condition – as opposed to the findings of the repex modelling.[309] Furthermore, the draft decision also emphasised that the allowance provided for this program was not based on the repex model output but a notional amount. As Nuttall Consulting stated:

> an allowance was recommended based upon a “notional” 2011 amount that was not determined from the calibrated repex model output. The notional amount was based upon expenditure levels for similar asset replacements for Powercor, which we considered was a reasonable proxy given its similar number of zone substations and age. We did then scale this amount to account for further aging of the network by using the rate of increase given by the calibrated repex model. However, it is important to appreciate that we consider that this would be a conservative estimate of the annual increase from the notional amount (i.e. it is most likely to overstate the rate of increase from the notional amount) specifically due to the long lives assumed in the calibrated repex model (i.e. shorter lives would have predicted a lower rate of increase of expenditure). [310]

Regarding SP AusNet's comments regarding:

- DPv test results: the draft decision considered that the test data did not indicate that all transformers were near a level that indicated an impending failure or clearly demonstrated the volumes proposed. Furthermore, the AER notes that SP AusNet has not provided any information that would allow Nuttall Consulting to

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307 SP AusNet, *Revised regulatory proposal: RQM response to draft decision*, July 2010, pp. 33–55.
308 ibid., pp. 15–16.
309 AER, *Draft decision*, pp. 381–383.
310 Nuttall Consulting, Victorian Electricity Distribution Revenue Review, October 2010, p. 191.

adjust the estimates to better reflect the "most likely" actual winding condition or remaining life

- Consideration of other information: The AER considers the DP value to be an important consideration for its review of whether a transformer replacement is prudent and efficient expenditure. The AER notes that the condition information alone does not justify the scale of the proposed program.[311]

SP AusNet further commented that it was unable to calibrate/validate its models. In this regard, SP AusNet stated that its transformers and circuit breakers are not managed under a "run to fail" policy. As such, it was not possible for there to be data in respect of the calibration process. SP AusNet also provided additional information on what it considers to be calibration which included failure probability, consequence calculations, and NPV analysis of options. The AER has reviewed this information and is not persuaded by it. Firstly, the AER considers that "run to failure" data is not required for the calibration process. Secondly, given that SP AusNet's risk models made predictions from 2005 of failure probabilities, consequences, and risks, the AER considers that SP AusNet could use this information as a validation process against actual outcomes in the current regulatory period.[312]

The AER notes SP AusNet's comments regarding the probability of failure across a number of years. However, the AER considers that the probability utilised by SP AusNet relatively high compared to its own historical failure rates.

The AER also notes that Nuttall Consulting considers that the other modelling conducted by SP AusNet may be biasing the analysis towards replacement rather than other options as per clause 6.5.7 (e)(10). This is evident in SP AusNet's NPV analysis for transformers where the assumptions utilised were not using SP AusNet's condition information (the mean and standard deviation of asset lives were not in accordance with SP AusNet's experience). This has resulted in the model predicting the probability of failure earlier in the period - thus increasing the relative NPV towards replacement rather than refurbishment.[313]

The AER acknowledges that the lives used in its repex model were well above that of industry benchmarks. The AER notes that benchmark lives and failure rates are a starting point in an analysis where no records exist as to the observed in-service condition and failure rate of an item of plant. SP AusNet though specifically references its own asset management plans and condition based assessments as a basis for its forecasts. The AER considers that a prudent DNSP will have reliable records in this regard and therefore will not need to rely on generic estimates that are not specific

[311] The degree of polymerization (DP) test is another means for assessing insulation aging. This test is performed on paper samples. The DP test provides an estimate of the average polymer size of the cellulose molecules in materials such as paper and pressboard. Generally, paper in new transformers has a DP of about 1000. Aged paper with a DP of 200–260 has little remaining mechanical strength, and therefore makes windings more susceptible to mechanical damage during movement, particularly during extreme events such as through-faults. A critical piece of condition information concerns the winding insulation which the DP test assesses, as this is the most critical factor that defines the end of life of the transformer.
Nuttall Consulting, Victorian Electricity Distribution Revenue Review, October 2010, p. ;
SP AusNet, *Revised regulatory proposal: RQM response to draft decision*, July 2010, pp. 34–72.

[312] SP AusNet, *Revised regulatory proposal: RQM response to draft decision*, July 2010, pp. 34–35

[313] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 195.

to their own circumstances. Regardless, given that the benchmarks quoted by SP AusNet would have over-forecast historical replacement levels by a considerable margin, the AER does not consider that these benchmarks can be considered a reasonable gauge of the prudency of the future requirements. The AER also notes that Nuttall Consulting has tested these benchmark lives against historical replacement volumes. Nuttall Consulting concluded that the lives quoted by SP AusNet would have over-forecast historical replacement levels by a considerable margin. A detailed discussion of asset lives can be found in section P.3.10.9.[314]

Based on its analysis, the AER maintains that SP AusNet has not adequately demonstrated that its modelling is calibrated correctly, and on balance considers that it would most likely overstate replacement needs.

The AER, however, agrees with Nuttall Consulting that the allowance provided for in the draft decision may be insufficient to capture all assets categories for zone substation replacement. In the AER's experience an allowance for sundry costs in a capital project would lie in the range of 0 to 30 per cent. Nuttall Consulting has recommended the mid point of this range taking into account the level of detail contained in the estimates of SP AusNet. This selection appears to be reasonable to the AER. The AER therefore considers that a contingency allowance of 15 per cent will address this issue. In addition to this additional adjustment, the repex model has been recalibrated to reflect 2009 expenditure and this has raised the allowance for this function code significantly.[315]
Given the above the AER considers that SP AusNet's forecasts are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers).

Accordingly, the AER’s conclusion on SP AusNet's RQM capex is set out in Table P.19.[316]

Recoverable works

SP AusNet's revised regulatory proposal did not discuss this category nor provided any additional information.

As SP AusNet did not discuss the decision on recoverable works expenditure, the AER maintains its draft decision allowance for this category.[317]

AER conclusion

For the reasons outlined above, the AER is not satisfied that SP AusNet's forecast RQM capex reasonably reflects the capex criteria, including the capex objectives. The AER agrees with Nuttall Consulting that the RQM allowance for SP AusNet should be adjusted as follows:

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314 ibid., 196.
315 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, pp. 195–196;
316 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4) and (5) are particularly relevant to this analysis.
317 AER, *Draft decision*, pp. 384–385

Table P.19 AER conclusion on SP AusNet's RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015
Proposed	71.4	85.3	75.9	76.7	92.6
Less					
Moved to ESL[a]	– 37.1	–40.6	–42.9	–45.9	–49.8
Zone substation replacement	–9.1	–19.6	–7.5	–5.1	–16.6
Recoverable works	–1.6	–1.6	–1.6	–1.7	–1.7
AER conclusion	**23.6**	**23.6**	**23.7**	**24.1**	**24.5**

(a) Includes expenditure for cross-arms, conductor replacement, poles replacement, EDO fuses, bird and animal proofing and enhanced control and electrical protection.

P.3.10.15 United Energy

Draft decision outcomes and revised regulatory proposal forecast

Following the adjustments detailed in Table P.20 the AER was satisfied that an estimate of $137.1 million for United Energy’s forecast RQM capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered these adjustments were the minimum necessary for it to be satisfied that United Energy’s RQM capex forecast reasonably reflected the capex criteria.

United Energy's revised regulatory proposal included a RQM capex proposal of $280.3 million ($2010) for the forthcoming regulatory control period. United Energy's revised capex proposal is set out in Table P.21.

Table P.20 AER draft conclusion on RQM capex for United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	60.6	58.3	56.5	50.5	51.2	277.2
less function code adjustments						
OH line replacement	2.2	2.7	2.9	3.2	4.3	15.2
Sub T installation replacement	4.4	4.6	4.9	3.9	2.6	20.4
Pole tops replacement	12.3	14.4	15.7	10.3	10.0	62.6
Reliability maintained (performance)	10.1	8.7	8.3	6.1	5.6	38.9
total adjustments	29.0	30.3	31.8	23.5	22.4	137.1
AER's draft decision	**31.6**	**28.0**	**24.7**	**27.0**	**28.8**	**140.1**

Source: AER draft decision, July 2010, p. 393.

Table P.21 United Energy's initial and revised RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Initial proposal	60.6	58.3	56.5	50.5	51.2	277.2
Revised proposal	61.8	58.9	57.1	50.8	51.8	280.3
Difference	**1.2**	**0.6**	**0.6**	**0.3**	**0.6**	**3.1**

Source: United Energy, Regulatory proposal, November 2009, template 2.1; Revised regulatory proposal, RIN, July 2010, template 2.1.

Zone substation plant replacement

United Energy's revised regulatory proposal forecast $32.6 million ($2010) in the forthcoming regulatory control period for the replacement of zone substation plant equipment. The AER's draft decision rejected United Energy's initial proposal of $31.1 million ($2010) for this function code and recommended an allowance of $10.1 million ($2010).

United Energy's revised regulatory proposal raised several issues for consideration. United Energy commented that:

- Zone substation transformers are vital and costly pieces of equipment in a distribution network, and it is not acceptable to allow the risk of failure to become excessive, because a failure will have a severe impact on the business and customers.
- For all this and other reasons detailed in the draft decision, United Energy has rejected a run-to-failure strategy for zone substation transformers; and this is regarded as unacceptable industry practice.
- The AER's draft decision accepted that many of the transformers proposed for replacement by United Energy, are in an advanced state of ageing, but still concluded they still may have around 5 – 10 years of remaining life. United Energy can see no reasonable basis for drawing this conclusion and rejects the conclusion totally. All transformers proposed for replacement have been subject to extensive testing and analysis of their insulation to determine that the degree of polymerisation (DP) of the winding insulation will be at or below a value of 200 within the forthcoming regulatory control period. At a DP value of 200, paper insulation has no mechanical strength and any shock to the winding (such as that caused by current flowing to a fault on a distribution feeder) is likely to cause the insulation to fail and the transformer to fault.

United Energy's revised regulatory proposal also included:

- a revised strategic planning paper for its zone substation circuit breaker replacement program
- and a report by Utility Engineering solution on the Nuttall Consulting report.

The AER had reviewed and considered all information provided to it as part of the determination process. Regarding the AER concerns about the impacts of reliability on customers, United Energy's revised regulatory proposals included additional information that quantified these potential impacts. On United Energy's assumptions regarding the potential impact of climate change on its network the AER does not agree with this view. The AER considers that climate change effects are a continual, progressive effect that have been and will continue to occur over time. The impact of past climate related events will already be reflected in historical expenditure whilst future capital requirements should be reflected in changed industry design and operational standards for plant and equipment. The AER does not consider a prudent business should speculatively incur costs to change design standards on an ad-hoc basis. As the AER has had regard to historical expenditure in formulating this allowance the AER considers that no further allowance should be made. The AER maintains the position as stated in chapter 8 of this final decision for the reasons set out therein.

In addition to this, the AER has reviewed and considered the materials to support this impact on customers – one of the bases for this calculation being climate change – and considers that there was insufficient justification provided for the model inputs that generated the conclusion. The AER also considers that United Energy would need to provide and justify its reliability models/assumptions to substantiate that such a significant increase in expenditure should occur in the forthcoming regulatory control period.[318]

With respect to the AER's concerns about United Energy's high level risk analysis for circuit breakers replacements, United Energy's revised regulatory proposal included additional qualitative risk commentary about the potential risks it faced. The AER has reviewed this information and agrees with Nuttall Consulting that there was insufficient justification:

- on how United Energy determined risks
- how this risk will change in the forthcoming regulatory control period

[318] Assumptions in the following AMPs. United Energy, *Asset strategy strategic planning paper zone substation circuit breaker replacement program*, July 2010, pp. 16–17; United Energy, *Asset strategy strategic planning paper zone substation transformer replacements*., July 2010, pp. 21–22; Email, UED's response to AER queries dated 08/09/2010 impact on customers: S factor model for EDPR - UED Asset Replacement; Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. ; For transformers UED assumed that based on historical failure rates of 11.1% for a transformer that is due for replacement, and 1% for a transformer in good condition, and 34.3% for failure of an associated 66kV line, the likelihood of a loss of supply can be calculated. If replacements are made to maintain expenditure levels at the average of the 2006-2009 period, and taking account of the number of transformers at each station, the estimated SAIDI impact of failures is 6.9 minutes. For circuit breaker UED assumed that a failure of a 66kV circuit breaker may result in the loss of a zone substation for about 60 minutes. The condition of 66kV circuit breakers is closely monitored, providing a good indication of the remaining life. All circuit breakers that fail the condition test are likely to fail to operate correctly within 4 years if retained in service. If replacements are made to maintain expenditure levels at the average of the 2006-2009 period, and taking into account the different impacts of a failed bus tie circuit breaker and a 66kV line circuit breaker, the SAIDI impact is 1.7 minutes.

- how the change in risk will lead to the significant increase in replacement expenditure.[319]

With respect to transformer replacement, the AER agrees with Nuttall Consulting that while four to five of United Energy's transformers have condition data that supported a need to replace them in the forthcoming regulatory control period, the AER considers that United Energy appears to plan to replace transformers when the modelled DPv is well beyond 200.[320] As such, the AER maintains that United Energy's model “on average” will overstate the degradation. Consequently, the AER considers that United Energy will most likely manage the risks and defer replacing these transformers in the forthcoming regulatory control period. The AER agrees with Nuttall Consulting that the adjustment in the final decision will address United Energy's transformer replacement needs.[321]

The AER notes the report provided as part of the revised regulatory proposal from Utility Engineering Services. A summary of the views from this report was discussed in section P.3.8. The AER has reviewed this document. Other than a critique of the AER's review process and it repex model, this document contained no relevant fact or evidence to support United Energy's proposed replacement capex.

Given the above the AER considers that United Energy's forecast are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

- has not demonstrated an underlying need for a step increase in investment – clauses 6.5.7(c)(1–3)

- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)

- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, United Energy has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c)(1–3).

The AER, however, agrees with Nuttall Consulting that the allowance provided in the draft decision may be insufficient to capture the all transformers replacements. Similar to other DNSPs the AER considers that the repex model should be

319 United Energy, *Asset strategy strategic planning paper zone substation circuit breaker replacement program*, July 2010. Several risks and impacts are detailed within this document; Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 221.

320 United Energy, *Revised regulatory proposal, Appendix D-28 - UED - Zone Substation Transformer Replacements, appendix B*, July 2010, pp. 1–2.

321 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 221.

recalibrated to reflect 2009 expenditure. These adjustments have raised the allowance for this function code significantly.[322]

Accordingly, the AER’s conclusion on United Energy's RQM capex is set out in Table P.22.[323]

Reliability and performance

United Energy's revised regulatory proposal forecast $53.6 million ($2010) in the forthcoming regulatory control period for reliability and performance replacements. The AER's draft decision rejected United Energy's initial proposal of $57.9 million ($2010) for this function code and recommended an allowance of $19.1 million ($2010).

United Energy's revised regulatory proposal raised stated that the primary major expenditure for this function code related to its program to install high voltage aerial bundle cable and the installation of harmonic filters. United Energy also commented:

> For the high voltage aerial bundled cable (ABC) program United stated that the driver for the project was in response to the deterioration of performance of its network. Whether the deterioration is due to climate change or not, the fact is that network performance, as indicated by SAIDI is deteriorating at a rate of 6.5 minutes per year.
>
> For the harmonic filters program the driver appears to be for power quality reasons. United Energy is required under its licence conditions to meet certain requirements for harmonics on the network. On the HV network, total harmonic distortion (THD) level of less than 3 per cent is required. Presently there are more than 19 zone substations on the network with THD above this level.
>
> The program proposed for the 2011 -2015 period also includes provision of harmonic filters in the 10 worst performing substation so that customers are supplied within the required power quality limits. In addition harmonic tuning reactors are planned for 8 capacitor bank to address equipment failure issues.[324]

United Energy's revised regulatory proposal also included a revised strategic planning paper for its power quality.

As a result of the ESV recommendation of the safety related drivers behind the HV ABC replacement program, this program has been transferred and assessed under Environmental Safety and Legal capex.

In assessing United Energy's regulatory proposals and the supporting information, the AER maintains its draft decision position that United Energy has not reasonably demonstrated that the increase in expenditure is prudent and efficient in accordance with the NER.

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322 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 222.

323 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.

324 United Energy, *Revised regulatory proposal*, p. 135.

Given the significant increase in expenditure in the forthcoming regulatory control period, the AER considers that United Energy would need to provide detailed reliability and economic analysis to justify its proposal. The AER also notes ones that ones of the drivers to these programs appear to be climate change. On United Energy's assumptions regarding the potential impact of climate change on its network, the AER does not agree with this view. The AER considers that climate change effects are a continual, progressive effect that have been and will continue to occur over time. The impact of past climate related events will already be reflected in historical expenditure whilst future capital requirements should be reflected in changed industry design and operational standards for plant and equipment. The AER does not consider a prudent business should speculatively incur costs to change design standards on an ad hoc basis.

Regarding to the power quality component, the AER has considered the information in United Energy's power quality strategic planning paper. The AER agrees with Nuttall Consulting that this paper does not adequately justify the proposed increase in expenditure or the timing of the programs, particularly in the context of how United Energy has managed these matters in the current period. That is, the information provided by United Energy lacked the detailed analysis that shows how United Energy has identified and profiled its quality of supply projects. As United Energy is suggesting that compliance issues presently exist and it is only proposing to address a proportion of these, it appears reasonable to consider that it can manage these risks with expenditure that is in line with the historical trend. Furthermore, while many qualitative comments were made in relation to the associated reliability benefits of these programs, no detailed analysis were given on how or whether these benefits would be realised should United Energy be given these expenditure.[325]

Further, the AER considers that the overall increase in United Energy's capex allowance in this final decision (from the draft decision) will be more than adequate to allow United Energy to undertake significant works to address its reliability issues.[326]

Given the above the AER considers that United's forecasts are not reasonable estimates and it does not support the objective of the NEO (it is unclear on the evidence available whether this expenditure constitutes efficient investment in or efficient operation and use of electricity services for the long term interests of consumers) as it:

- has not demonstrated an underlying need for a step increase in investment – clauses 6.5.7(c)(1–3)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing – clause 6.5.7(c)(2)
- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal – clause 6.5.7(c)(2)

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325 United Energy, *Asset strategy strategic planning paper power quality*, July 2010. Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, October 2010, p. 224.

326 ibid., 224.

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, United Energy has not established a clear link between its use of engineering judgement and economic efficiency – clauses 6.5.7(c) (1–3).

Accordingly the AER's conclusion, based on its repex model outputs, on United Energy's RQM capex is set out in Table P.22.[327]

Services

The AER's draft decision accepted United Energy's forecast for this category. However for the revised regulatory proposal, United Energy submitted its entire RQM capex forecast to the ESV for assessment. As a result of the ESV investigation, where the ESV has:

- accepted United Energy's safety case, the AER has re-assessed these programs under environmental safety and legal category[328]
- rejected United Energy's safety case, the AER has re-assessed this program under RQM.[329]

United Energy's revised regulatory proposal did not respond to or disagree with the draft decision in relation to this category. Further, United Energy's revised regulatory proposal did not include any new information for this category.

The AER has reassessed this category and for the reasons outlined in the draft decision the AER is satisfied that United Energy's forecast for the RQM component of services forms part of a total forecast capex that reasonably reflects the capex criteria.

Pole top replacement

The AER's draft decision rejected United Energy's forecasts for the pole tops replacement category. In its revised regulatory proposal United Energy submitted most of the programs belonging to this category to the ESV for assessment. United Energy however did not submit the capacitor banks replacement, high voltage fuse replacement and surge diverter replacement programs to the ESV for assessment.

The AER has reassessed these programs and considers that the high voltage fuse and surge diverter replacement programs should be considered under the Environmental Safety and Legal category due to the safety related drivers.

For capacitor banks replacement, the AER notes United Energy's assessment concerning the significant ramp-up in the number of components failing during the current regulatory period. The AER also notes that United Energy has conducted a study of historical failure data to form its forecast for the forthcoming regulatory control period. Further, in its options analysis United Energy concluded the best

327 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.

328 Includes RMJ, RMK, RML and RMU projects as per UED's capex plan.

329 Include the RMF project as per UED's capex plan.

approach for capacitor banks replacements was to replace the defective parts based on inspection.[330]

Based on the above, the AER agrees with United Energy approach for the replacement of pole mounted capacitor banks and is satisfied that United Energy's forecasts of $3.8 million ($2010) for this program forms part of a total forecast capex that reasonably reflects the capex criteria.[331]

AER conclusion

For the reasons outlined above, the AER is not satisfied that United Energy's forecast RQM capex reasonably reflects the capex criteria, including the capex objectives. The AER agrees with Nuttall Consulting that the RQM allowance for United Energy should be adjusted as follows.

Table P.22 AER final conclusion on United Energy RQM capex ($'m, 2010)

	2011	2012	2013	2014	2015
Proposed	61.0	58.0	55.8	49.4	50.1
Less					
Moved to ESL[a]	–25.4	–29.0	–28.4	–24.6	–26.6
Zone substation replacement	–2.6	–2.5	–3.1	–1.7	–0.3
Reliability performance	–6.7	–5.5	–4.7	–2.3	–1.6
AER conclusion	**26.1**	**20.9**	**19.6**	**20.8**	**21.6**

(a) Include poles, pole top structure, conductor, fire mitigation and some services replacement programs.

330 United Energy, *Asset strategy strategic planning paper pole mounted capacitor banks*, July 2010, pp. 4 and 6–8.

331 In coming to this view the AER has had regard to the capex factors. Capex factors (1), (2), (3), (4), and (5) are particularly relevant to this analysis.

P.4 Environmental, safety and legal

This section considers the Victorian DNSPs' proposals on the environmental, safety and legal capex category.

As noted at the beginning of the capex chapter (chapter 8) of this final decision, each Victorian DNSP proposed allowances for environmental, safety and legal capex as a component of its total proposed forecast capital expenditure for the 2011–15 regulatory control period. The assessment of this component is relevant to determining whether the AER is satisfied that the total proposed forecast capital expenditure or its estimate of the required capital expenditure reasonably reflects the capital expenditure criteria.

Specifically, this section assesses the proposed allowances and what the level of efficient direct cost expenditure for environmental, safety and legal capex which a prudent operator, in the circumstances of each Victorian DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capital expenditure objectives.

Therefore, this section gives the reasons for the AER's final decision in respect of the direct costs relating to the Victorian DNSPs' respective revised regulatory proposals on environmental, safety and legal capex.

That is, in accordance with NER cl.6.12.2, this section sets out the basis and rationale for the AER's final decision including:[332]

- details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the AER
- the values adopted by the AER for the input variable in any calculations and formulae, including:
  - whether those values have been taken or derived from the Victorian DNSPs' initial or revised regulatory proposals, and
  - if not, the rationale for the adoption of those values
- details of any assumptions made by the AER in undertaking any material and quantitative analyses
- reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretions, as referred to in chapter 6 of the NER, for the purposes of the AER's final decision.

Approach

Where a Victorian DNSP accepted the AER's draft decision on the direct costs for the environmental, safety and legal capex, the AER has approved that same direct cost amount(s) in its final decision.

[332] NER, clause 6.12.2.

Where a Victorian DNSP did not accept the AER's draft decision on the environmental, safety and legal capex direct costs, the AER has considered whether the revised regulatory proposal in respect of that proposed capex reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant Victorian DNSP would require to meet the capex objectives.

That is, having regard to the capex factors set out at NER cl.6.5.7(e), and particularly:

- the information included in or accompanying the building block proposal
- submissions received in the course of consulting on the building block proposal
- analysis undertaken by or for the AER and published before the distribution determination is made in its final form
- benchmark capital expenditure that would be incurred by an efficient distribution DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods

the AER has considered whether the proposed projects are in accordance with good industry practice including whether:

- there is a justifiable need for the proposed capex
- the proposed projects have been objectively and competently analysed to a standard that is consistent with good industry practice
- the proposed projects align with strategic capex plans and policies.

The AER sought explanation of the drivers of any proposed step changes in the environmental, safety and legal capex. The historical underlying trend in expenditure in the environmental, safety and legal capex was used as the starting point to assess whether a step change (increase or decrease) in expenditure had been proposed. However, given that the historical trend cannot completely determine future requirements, the AER requested the Victorian DNSPs to provide relevant economic analysis which clearly demonstrated the need to undertake the proposed projects in the forthcoming regulatory control period. The AER expected the analysis would demonstrate how engineering judgements had been translated into step changes in expenditure and be supported by cost-benefit analysis including options analysis. Having said that, the AER also expected the analysis would be appropriate in respect of the materiality of the proposed project expenditures as a proportion of the total capex for the environmental, safety and legal capex.

The AER must allow each Victorian DNSP adequate funding to recover at least its respective efficient costs of providing direct control services. The AER is also aware that each Victorian DNSP must also satisfy safety and other regulatory and legislative obligations while managing its respective networks in accordance with good electricity practices. Therefore, in assessing each Victorian DNSP's proposed expenditures in environmental, safety and legal capex, the AER considered:

- whether the proposed projects aligned with strategic capex plans and policies
- changes in timing have been considered to ensure prudent decision-making
- processes or systems for project approval reflected good governance and business practices for undertaking capital projects
- cost-estimating processes incorporate feed-back from specific experience.

Where the AER has not accepted a Victorian DNSP's revised regulatory proposal, in respect of the direct costs of projects proposed in environmental, safety and legal capex, the AER has made the minimum necessary change to the Victorian DNSP's forecast capex direct cost expenditure.

The AER's assessment and final decision on a realistic expectation of the demand forecast and costs inputs required to achieve the capex objectives are set out at chapter 5 and appendix K respectively of this final decision. The AER's final decision on the total capex reasonably required by each Victorian DNSP is set out at chapter 8 and includes amounts for the direct costs (as set out in this appendix) for environmental, safety and legal capex, as adjusted for overheads, real cost increases and margins.

P.4.1 AER draft decision

The AER considered that the Victorian DNSPs had not demonstrated that there will be material step changes to their compliance with:

- environmental legislation and regulations, particularly the EPA environment protection policies or
- Victorian safety legislation and regulations.

That is, the Victorian DNSPs had not identified:

- any regulatory obligations or requirements that will take effect for the first time in the forthcoming regulatory control period
- any changes in regulatory obligations or requirements in the forthcoming regulatory control period that will materially affect the environmental, safety and legal capex requirement in the forthcoming regulatory control period.

The AER sought clarification from Energy Safe Victoria (ESV) regarding the nature of any change in safety compliance risks faced by the Victorian DNSPs. ESV confirmed that the regulatory obligations of the Victorian DNSPs had not altered as a result of the amendments to the Electricity Safety Act 1998 and associated regulations. Therefore, the AER did not accept the Victorian DNSPs' proposed capex amounts and substituted amounts based on a continuation of the historical expenditure trend in this capex category.

The historical underlying trend of capex was used by the AER as the starting point for assessing the reasonableness of the proposed environmental, safety and legal capex because the AER considered that the Victorian DNSPs appear to spend significantly less than forecast and actual capex tends to follow a gradually increasing trend.

Further, as the Victorian DNSPs retained discretion to prioritise their work programs and allocate their resources to meet customer requirements while managing and operating their networks in accordance with good electricity industry practice, the AER considered that each Victorian DNSP had at times over or underspent relative to the ESCV benchmark allowance on the basis of its own assessments of whether it was efficient to do so.

In identifying the underlying trend, the AER considered data for the years 2004 to 2008 inclusive. The 2009 and 2010 data provided by the Victorian DNSPs was considered to be forecast data and therefore not considered to be part of the historical trend.

P.4.1.1 CitiPower

Table P.23 sets out CitiPower's initial proposed environmental, safety and legal capex and the AER's draft decision.

Table P.23 Environmental, safety and legal capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower initial regulatory proposal	3.6	3.2	3.2	3.0	3.0	16.0
AER draft decision	1.2	1.2	1.2	1.2	1.2	6.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 395, 404.

P.4.1.2 Powercor

Table P.24 sets out Powercor's initial proposed environmental, safety and legal capex and the AER's draft decision.

Table P.24 Environmental, safety and legal capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor initial regulatory proposal	12.9	8.7	9.8	8.9	7.8	48.2
AER draft decision	6.7	6.7	6.7	6.7	6.7	33.5

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 395, 404.

P.4.1.3 Jemena Electricity Networks (JEN)

Table P.25 sets out JEN's initial proposed environmental, safety and legal capex and the AER's draft decision.

Table P.25 Environmental, safety and legal capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN initial regulatory proposal	4.9	7.7	6.0	4.4	3.9	27.0
AER draft decision	5.0	5.0	5.0	5.0	5.0	25.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.

Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 395, 404.

P.4.1.4 SP AusNet

In the case of SP AusNet, the AER reallocated the proposed programs for 'pre-emptive replacement' based on age/condition of assets from the environmental, safety and legal capex category to the reliability and quality maintained capex category. As a result, these projects (and associated expenditures) were not assessed as part of the environmental, safety and legal capex category in the forthcoming regulatory control period.

Table P.26 sets out SP AusNet's initial proposed environmental, safety and legal capex and the AER's draft decision.

Table P.26 Environmental, safety and legal capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet initial regulatory proposal	22.8	19.4	22.6	16.0	13.9	94.9
AER draft decision	1.1	1.1	1.1	1.1	1.1	5.5

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.

Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 395, 404.

P.4.1.5 United Energy

Table P.27 sets out United Energy's initial proposed environmental, safety and legal capex and the AER's draft decision.

Table P.27 Environmental, safety and legal capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy initial regulatory proposal	15.6	9.1	11.1	7.9	7.4	51.1
AER draft decision	8.5	8.5	8.5	8.5	8.5	42.7

Note: Totals may not add due to rounding.

Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.

Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 395, 404.

P.4.2 Victorian DNSP revised regulatory proposals

P.4.2.1 CitiPower

CitiPower stated it did not contest the AER's draft decision with respect to environmental, safety and legal capex.[333] However, it did not actually accept the draft decision because it considered that the AER should include 2009 actual data in forecasting the environmental, safety and legal capex in the forthcoming regulatory control period by reference to historical expenditure.[334]

CitiPower also noted:[335]

- if the AER made its final decision consistent with its draft decision, it would not be in a position to complete all of the noise works contemplated in its initial regulatory proposal
- should a DNSP require capex to comply with an obligation, it should suffice to satisfy the AER, acting reasonably, that the capex required by a prudent and efficient operator to achieve the capex objectives for that DNSP to demonstrate that its proposed capex is the lowest means of achieving compliance
- the plans submitted under the Electrical Safety Management Regulations should be addressed by the AER as a nominated pass through.

Table P.28 sets out the AER's draft decision and CitiPower's revised environmental, safety and legal capex proposal.

Table P.28 Environmental, safety and legal capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	1.2	1.2	1.2	1.2	1.2	6.0
CitiPower revised regulatory proposal	1.1	1.1	1.1	1.1	1.1	5.5

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 404.

[333] CitiPower, *Revised regulatory proposal*, pp. 249, 309.
[334] ibid., pp. 249, 309–310.
[335] ibid., pp. 310–311.

P.4.2.2 Powercor

Powercor stated it did not contest the AER's draft decision with respect to environmental, safety and legal capex.[336] However, it did not actually accept the draft decision because it considered that the AER should include 2009 actual data in forecasting the environmental, safety and legal capex in the forthcoming regulatory control period by reference to historical expenditure.[337]

Powercor also noted:[338]

- if the AER made its final decision consistent with its draft decision, it would not be in a position to complete all of the noise works contemplated in its initial regulatory proposal
- should a DNSP require capex to comply with an obligation, it should suffice to satisfy the AER, acting reasonably, that the capex required by a prudent and efficient operator to achieve the capex objectives for that DNSP to demonstrate that its proposed capex is the lowest means of achieving compliance
- the plans submitted under the Electrical Safety Management Regulations should be addressed by the AER as a nominated pass through.

Table P.29 sets out the AER's draft decision and Powercor's revised environmental, safety and legal capex proposal.

Table P.29 Environmental, safety and legal capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	6.7	6.7	6.7	6.7	6.7	33.5
Powercor revised regulatory proposal	6.5	6.5	6.5	6.5	6.5	32.3

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15,* Draft decision, June 2010, p. 404

P.4.2.3 JEN

JEN did not accept the AER's draft decision. It considered the AER did not have adequate regard to the forward-looking nature of the capex objectives and the capex criteria in clause 6.5.7 of the NER and with the requirements in clause 6.12.3(f) of the NER.[339] That is, JEN considered that the AER had not substituted an amount or value that was determined on the basis of JEN's regulatory proposal or amended from its

[336] Powercor, *Revised regulatory proposal*, pp. 239, 297.
[337] ibid., pp. 239, 297.
[338] ibid., p. 298.
[339] JEN, *Revised regulatory proposal*, p. 165.

regulatory proposal only to the extent necessary to enable its approval in accordance with the NER.

JEN stated it did not agree with ESV's advice that the regulatory obligations of the Victorian DNSPs had not altered as a result of amendments to the Electricity Safety Act 1998 and associated regulations.[340] In JEN's opinion, the duty to "minimise as far as practicable" is a higher standard than the requirement to take "reasonable care". In its revised regulatory proposal, JEN stated it would be meeting with ESV to determine increases in the scope and volume of work required to meet its safety obligations. Therefore, JEN requested an opportunity to revise its costs following agreement with ESV, expected to be in mid-August 2010.[341]

JEN noted the AER's use of the historical expenditure trend assumed that JEN was currently compliant with relevant legislation. It considered that its proposed investments in power quality and reactive compensation at points of connection would address current non-compliance which it would "become aware of due to greater knowledge [based on data and other information gathered regarding its network]".[342]

Table P.30 sets out the AER's draft decision and JEN's revised environmental, safety and legal capex proposal.

Table P.30 Environmental, safety and legal capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	5.0	5.0	5.0	5.0	5.0	25.0
JEN revised regulatory proposal	6.3	8.3	6.0	4.7	4.5	29.7

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.

Source: JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 404.

P.4.2.4 SP AusNet

SP AusNet accepted the allowance set out in the AER's draft decision because it considered the AER's allowance of $5.5 million ($2010) was consistent with its own forecast total capex requirement for:[343]

- environmental, bunding, security
- occupational health and safety – replacement of current transformers
- occupational health and safety – replacement of disconnectors
- occupational health and safety – replacement of silicon carbide gap arrestors.

340 ibid., p. 165.
341 ibid., p. 168.
342 ibid., p. 166.
343 SP AusNet, *Revised regulatory proposal*, pp. 137–138.

Table P.31 sets out the AER's draft decision and SP AusNet's revised environmental, safety and legal capex proposal.

Table P.31 Environmental, safety and legal capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	1.1	1.1	1.1	1.1	1.1	5.5
SP AusNet revised regulatory proposal	1.1	1.1	1.1	1.1	1.1	5.3

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.
Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 404.

P.4.2.5 United Energy

United Energy did not accept the AER's draft decision. It stated its proposed increase in environmental, safety and legal capex was to meet new requirements and obligations under the Electricity Safety Management Scheme (ESMS) regulations; partly due to the new regulations and partly due to its re-evaluation of risks.[344] In particular, it considered the increasing expenditure trend in this capex category was the result of increasing expenditure on two projects:[345]

- replacement of neutral screened overhead services
- the installation of ground fault neutralisers.

United Energy considered its proposed capex was the minimum required for it to meet its requirements under the ESMS.

Table P.32 sets out the AER's draft decision and United Energy's revised environmental, safety and legal capex proposal.

Table P.32 Environmental, safety and legal capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	8.5	8.5	8.5	8.5	8.5	42.7
United Energy revised regulatory proposal	21.7	14.9	12.8	9.6	9.1	68.1

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.
Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.

344 United Energy, *Revised regulatory proposal*, p. 144.
345 ibid., p. 143.

AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 404.

P.4.3 Submissions

The AER received submissions from the Energy Users Coalition of Victoria (EUCV) and Grid Australia on the environmental, safety and legal capex proposed by the Victorian DNSPs.

The EUCV considered that there had been "no changes in external regulatory requirements in the areas of environmental, safety and legal capex that would constitute a step change".[346] On this basis, the EUCV agreed with the AER's approach of not allowing increases in environmental, safety and legal capex.

Grid Australia considered the AER had not given the same weight to "programs to address network security and environmental risks" as a cost driver of capex in assessing the Victorian DNSPs' capex proposals compared with its approach in decisions for the Queensland, NSW and South Australian jurisdictions.[347]

P.4.4 Consultant review

In the case of environmental, safety and legal capex, Nuttall Consulting assessed:

- matters raised in the revised regulatory proposals submitted by CitiPower and Powercor
- project unit costs proposed by each of the Victorian DNSPs in respect of projects supported by ESV.

P.4.4.1 CitiPower

Nuttall Consulting agreed with CitiPower that 2009 actual data should be included in trend analysis.[348] Nuttall Consulting also stated the average capex during 2006–2009 was $1.451 million ($2010) and that CitiPower's revised regulatory proposal was consistent with the average level of expenditure in the 2006–10 regulatory period.[349]

Table P.33 sets out Nuttall Consulting's recommendation on environmental, safety and legal capex for CitiPower in the forthcoming regulatory control period.

346 Energy Users Coalition of Victoria, *Australian Energy Regulator Victorian Electricity Distribution Revenue Reset AER Draft Decisions and Revised Regulatory Proposals on CitiPower, Jemena, Powercor, SP AusNet and United Energy Applications: A response by Energy Users Coalition of Victoria*, August 2010, p. 22.

347 Grid Australia, *Victorian Electricity Distribution Draft Decision 2011–15*, submission to the AER dated 19 August 2010, pp. 4–5.

348 Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 77.

349 ibid., p. 77.

Table P.33 Nuttall Consulting recommendation on CitiPower environmental, safety and legal capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on CitiPower environmental, safety and legal capex	1.5	1.5	1.5	1.5	1.5	7.3

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 77.

P.4.4.2 Powercor

Nuttall Consulting agreed with Powercor that 2009 actual data should be included in trend analysis.[350] Nuttall Consulting also noted that although Powercor's revised regulatory proposal stated it did not contest the AER's draft decision, Powercor's revised regulatory proposal was for an amount greater than the AER's draft decision.[351] As Powercor did not explain the basis for the proposed increased expenditures and did not provide any additional information to support its revised regulatory proposal, Nuttall Consulting recommended the AER's draft decision stand, subject to consideration of 2009 actual environmental, safety and legal capex[352]

Table P.34 sets out Nuttall Consulting's recommendation on environmental, safety and legal capex for Powercor in the forthcoming regulatory control period.

Table P.34 Nuttall Consulting recommendation on Powercor environmental, safety and legal capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on Powercor environmental, safety and legal capex	7.2	7.2	7.2	7.2	7.2	36.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 151.

P.4.4.3 JEN

Nuttall Consulting assessed JEN's revised regulatory proposal on environmental, safety and legal capex in respect of project unit costs proposed for projects supported by ESV.[353]

350 ibid., p. 150.
351 ibid., p. 150.
352 ibid., p. 150.
353 ibid., p. 119.

P.4.4.4 SP AusNet

Nuttall Consulting assessed SP AusNet's revised regulatory proposal on environmental, safety and legal capex in respect of project unit costs proposed for projects supported by ESV.[354]

P.4.4.5 United Energy

Nuttall Consulting assessed United Energy's revised regulatory proposal on environmental, safety and legal capex in respect of project unit costs proposed for projects supported by ESV.[355]

P.4.4.6 Assessment of unit costs for environmental, safety and legal capex projects

Nuttall Consulting assessed the unit costs of projects which were proposed by the Victorian DNSPs and subsequently supported by ESV as required to be undertaken in the forthcoming regulatory control period. Table P.35 sets out Nuttall Consulting's conclusions on the relevant proposed project unit costs.

[354] ibid., p. 198.
[355] ibid., p. 226.

Table P.35 Environmental, safety and legal capex project unit cost—direct cost ($'m, 2010)

Proposed project	Project unit cost ($2010, direct cost)		Nuttall Consulting comments
	DNSP proposal	Nuttall Consulting recommendation	
JEN			
Replacement of non-preferred services (per service)	[confidential]	[confidential]	JEN proposed cost is higher than current charge for new service connection
Removal of public lighting switch wire (per span)	[confidential]	[confidential]	Cost appears reasonable
Removal of SWER (per km)	Various project component rates provided	[confidential]	Cost is in reasonable range
Installation of Ground Fault Neutraliser (per installation)	Various project component rates provided	[confidential]	Cost is in reasonable range
Pole top fire mitigation (per pole top structure)	[confidential]	[confidential]	Cost appears reasonable. [confidential] calculated using information in JEN Capital and Operating Works Plan.
Pole top replacement (age and condition) (per pole top structure)	—	JEN proposed costs less 15 per cent	JEN's proposed costs are higher than costs proposed by other Victorian DNSPs
Pole replacement	—	Cost as proposed by JEN	Cost appears to be in reasonable range
Overhead conductor replacement (per km)	—	[confidential]	JEN's proposed costs are higher than costs proposed by Powercor and SP AusNet
SP AusNet			
Enhanced crossarm replacement	—	Cost as proposed by SP AusNet	Cost appears reasonable
Conductor replacements	—	Accepted in draft decision	—
HV pin type insulator replacements	—	Accepted in draft decision	—
EDO fuse replacements	—	Cost as proposed by SP AusNet	Cost appears reasonable

Enhanced protection and control – involving OCR/ACR replacements/upgrades	—	Cost as proposed by SP AusNet	Cost appears reasonable
Augment spans –habitat trees	—	SP AusNet proposed costs less 20 per cent	Cost appears high relative to costs proposed by United Energy.
United Energy			
Replacement of non-preferred services (per service)	[confidential]	[confidential]	United Energy proposed cost is higher than current charge for new service connection
Removal of public lighting switchwire (per span)	[confidential]	[confidential]	Cost appears reasonable
Removal of SWER (per km)	Various project component rates provided	[confidential]	Cost is in reasonable range
Installation of Ground Fault Neutraliser (per installation)	Various project component rates provided	[confidential]	Cost is in reasonable range
Pole top fire mitigation	[confidential]	[confidential] per insulator set [confidential] per crossarm [confidential] per pole top asset inspection	Cost appears to be in reasonable range [confidential] calculated using information in United Energy Capital and Operating Works Plan.
Pole top replacement (age and condition)	—	Accepted proposed rates	Cost appears low
Install ABC in high bushfire risk area (per metre)	HV ABC – LV ABC – [confidential]	HV ABC - LV ABC - [confidential]	Cost appears reasonable
Pole replacement	—	Accepted proposed rates	Cost appears reasonable
Overhead conductor replacement (per km)	—	[confidential]	United Energy's proposed costs are higher than costs proposed by Powercor and SP AusNet
Backup earth fault protection (per scheme)	[confidential]	[confidential]	Cost appears reasonable
Overhanging trees capex (underground, line	HV –	HV - [confidential]	Cost appears reasonable

relocation, ABC etc) (per span)	LV – [confidential]	LV - [confidential]

Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010,pp. 294–361.

P.4.5 Issues and AER considerations

In response to Grid Australia's submission that programs to address network security and environmental risks have not been appropriately weighted as cost drivers of the Victorian DNSPs' proposed capex, the AER maintains that it has recognised that complying with all applicable regulatory obligations or requirements associated with the provision of standard control services is a capex objective in making its decisions for the Victorian, Queensland, NSW and South Australian DNSPs.

P.4.5.1 Use of historical actual expenditure to forecast capex requirement in forthcoming regulatory control period

The AER agrees with the Victorian DNSPs that 2009 data should be used in historical expenditure analysis because audited 2009 regulatory accounts are now available.

P.4.5.2 Assessment of unit costs for environmental, safety and legal capex projects

The AER has considered the views on project unit cost submitted independently by the Victorian DNSPs and Nuttall Consulting respectively. In cases where the views of Nuttall Consulting and the Victorian DNSPs agree, the AER has accepted the Victorian DNSP's proposed project unit cost as being reasonable. Alternatively, where the Victorian DNSPs' and Nuttall Consulting's views do not agree, the AER has also considered third-party project unit cost information submitted by United Energy in support of its proposed capex in the forthcoming regulatory control period to inform its decision on what is a reasonable rate.[356]

Table P.36 sets out the AER's conclusions on the project unit costs which will be applied to project work volumes supported by ESV.

[356] United Energy, *Revised regulatory proposal*, Appendix B-4–Capital Expenditure Forecast.xls

Table P.36 Environmental, safety and legal capex project unit cost—direct cost ($'m, 2010)

Proposed project	Project unit cost ($2010, direct cost)	AER comments
Powercor		
Overhead conductor replacement (per km)	[confidential]	Powercor's proposed rate was calculated as the average of costs of historical project costs – including a high cost project for which the project driver was "Pole top reconstructions". The AER did not include the "pole top reconstructions"– driven project in its calculation of the unit cost, however, the AER used the same methodology as Powercor.
JEN		
Replacement of non-preferred services (per service)	[confidential]	Accepted rate as proposed by JEN. This rate is lower that the charge for new service connection in the forthcoming regulatory control period (refer to Appendix Q of this final decision).
Removal of public lighting switchwire (per span)	[confidential]	Accepted rate as proposed by JEN. Nuttall Consulting assessed JEN's cost as reasonable.
Removal of SWER (per km)	[confidential]	Accepted rate as proposed by JEN. Nuttall Consulting assessed JEN's cost as reasonable.
Installation of Ground Fault Neutraliser (per installation)	[confidential]	Accepted rate as proposed by JEN. Nuttall Consulting assessed JEN's cost as reasonable.
Pole top fire mitigation (per pole top structure)	[confidential]	JEN proposed a unit cost calculated as a weighted average of the cost of a ST crossarm and a HV crossarm. The proposed unit cost appeared high relative to other Victorian DNSPs. On this basis, the AER accepted Nuttall Consulting's recommendation to reduce the proposed unit cost by 15 per cent as reasonable.
Pole top replacement (age and condition) (per pole top structure)	[confidential]	JEN proposed a unit cost calculated as a weighted average of the cost of a ST crossarm, a HV crossarm and a LV crossarm. The proposed unit cost appeared high relative to other Victorian DNSPs. On this basis, the AER accepted Nuttall Consulting's recommendation to reduce the proposed unit cost by 15 per cent as reasonable.
Pole replacement (per pole)	[confidential]	Accepted rate as proposed by JEN. JEN proposed a unit cost calculated as a weighted average of the cost of a ST pole, a HV pole and a LV pole.

		Nuttall Consulting assessed JEN's cost as reasonable.
Undersized pole replacement (per pole)	[confidential]	Accepted rate as proposed by JEN. JEN proposed a unit cost calculated as a weighted average of the cost of a HV pole and a LV pole.
Pole staking (per pole)	[confidential]	Accepted rate as proposed by JEN. JEN proposed a unit cost calculated as a weighted average of the cost of a ST pole, a HV pole and a LV pole.
Undersized pole staking (per pole)	[confidential]	Accepted rate as proposed by JEN. JEN proposed a unit cost calculated as a weighted average of the cost of a HV pole and a LV pole.
Overhead conductor replacement (per km)	[confidential]	JEN's proposed costs are higher than costs proposed by Powercor and SP AusNet. The AER considered that JEN's unit cost would be higher than these Victorian DNSPs given that it covers a more urbanised area. Having considered the information submitted, the AER accepted Nuttall Consulting's recommendation as reasonable.
Service line clearance – overhead services requiring relocation (per service)	[confidential]	Accepted rate as proposed by JEN. Cost is as per replacement of non-preferred services
Service line clearance – overhead services requiring undergrounding (per service)	[confidential]	Accepted rate as proposed by JEN. Nuttall Consulting assessed JEN's cost as reasonable.
SP AusNet		
Enhanced crossarm replacement	Total proposed cost as derived from SP AusNet RIN (Sheet 2.1).	Transferred from reliability and quality maintained capex. Accepted rate as proposed by SP AusNet. Nuttall Consulting assessed SP AusNet's cost as reasonable.
Conductor replacements	Total proposed cost as per AER draft decision	Transferred from reliability and quality maintained capex. Accepted in draft decision
HV pin type insulator replacements	Total proposed cost as per AER draft decision	Transferred from reliability and quality maintained capex. Accepted in draft decision
Animal and bird proofing	Total proposed cost as per SP AusNet's 17 August 2010 response to AER information request	Transferred from reliability and quality maintained capex. Accepted rate as proposed by SP AusNet.

	dated 9 August 2010	
EDO fuse replacements	Total proposed cost as per SP AusNet's 17 August 2010 response to AER information request dated 9 August 2010	Transferred from reliability and quality maintained capex. Accepted rate as proposed by SP AusNet. Nuttall Consulting assessed SP AusNet's cost as reasonable.
Enhanced protection and control – involving OCR/ACR replacements/upgrades	Total proposed cost as per SP AusNet's 17 August 2010 response to AER information request dated 9 August 2010	Transferred from reliability and quality maintained capex. Accepted rate as proposed by SP AusNet. Nuttall Consulting assessed SP AusNet's cost as reasonable.
Augment spans – habitat trees	Total proposed cost as proposed by SP AusNet at page 109 of its revised regulatory proposal	Transferred from reinforcement capex. The AER considers the proposed works relate to trees which are very large/significant and are in areas where removal would have significant stakeholder and environmental impact.
United Energy		
Replacement of non-preferred services (per service)	[confidential]	Accepted rate as proposed by United Energy. This rate is comparable to the charge for new service connection in the forthcoming regulatory control period (refer to Appendix Q of this final decision).
Removal of public lighting switchwire (per span)	[confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as reasonable.
Removal of SWER (per km)	[confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as reasonable.
Installation of Ground Fault Neutraliser (per installation)	[confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as reasonable.
Pole top fire mitigation (per pole top structure)	Crossarm – Insulator set – Inspection, cleaning etc – [confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost (except for pole top inspection) as reasonable.
Pole top replacement (age and condition) (per pole top structure)	[confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as low.
Pole top – HV fuse replacement (per pole top structure)	[confidential]	Accepted rate as proposed by United Energy. United Energy's cost appears reasonable.

Pole top – surge diverter replacement (per pole top structure)	[confidential]	Accepted rate as proposed by United Energy. United Energy's cost appears reasonable.
Install ABC in high bushfire risk area (per metre)	HV ABC – LV ABC – [confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as reasonable.
Pole replacement (per pole)	[confidential]	Accepted rate as proposed by United Energy. United Energy's cost appears reasonable.
Pole staking (per pole)	[confidential]	Accepted rate as proposed by United Energy. United Energy's cost appears reasonable.
Overhead conductor replacement (per km)	[confidential]	United Energy's proposed costs are higher than costs proposed by Powercor and SP AusNet. The AER considered that United Energy's unit cost would be higher than these Victorian DNSPs given that it covers a more urbanised area. Having considered the information submitted, the AER accepted Nuttall Consulting's recommendation as reasonable.
Backup earth fault protection (per scheme)	[confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as reasonable.
Overhanging trees capex (underground, line relocation, ABC etc) (per span)	HV – [confidential] LV – [confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as reasonable.
Service line clearance – overhead services requiring relocation (per service)	[confidential]	Did not accept rate as proposed by United Energy. The AER's substitute rate is as per replacement of non-preferred services
Service line clearance – overhead services requiring undergrounding (per service)	[confidential]	Accepted rate as proposed by United Energy. Nuttall Consulting assessed United Energy's cost as reasonable.

Source: Powercor, *Response to information requested 31 August 2010*, 7 September 2010; JEN, *Response to information requested 26 August 2010*, 8 September 2010; SP AusNet, *Response to information requested 26 August 2010*, 3 September 2010; United Energy, *Response to information requested 26 August 2010*, 8 September 2010; United Energy, *Revised regulatory proposal*, Appendix B-4–Capital Expenditure Forecast.xls; Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 145–147, 294–361.

P.4.5.3 CitiPower

CitiPower stated it did not contest the AER's draft decision with respect to environmental, safety and legal capex, however, it considered the AER should include

2009 actual data in its trend analysis and in forecasting the environmental, safety and legal capex required in the forthcoming regulatory control period by reference to historical expenditure.[357] The AER has included 2009 actual data in its analysis.

Following the draft decision, the AER requested the assistance of ESV in consultation with the Victorian DNSPs, in assessing whether there was a primarily safety-driven need for the Victorian DNSPs' proposed works and the associated works volumes in the forthcoming regulatory control period. Meetings were held between ESV and each of the Victorian DNSPs to discuss these matters. CitiPower did not submit to ESV in respect of its environmental, safety and legal capex works in the forthcoming regulatory control period.

However, in assessing CitiPower's proposed reliability and quality maintained capex, the AER identified the works programs, as set out at table P.37, which are primarily safety-driven and need to be undertaken by CitiPower in the forthcoming regulatory control period. These work programs have been included in the AER's final decision on CitiPower's environmental, safety and legal capex . Further, as safety considerations are the primary driver of the need for these projects in the forthcoming regulatory control period, ESV will monitor CitiPower's completion of these works.

Table P.37 Proposed reliability and quality maintained capex projects identified by the AER as being primarily safety driven—CitiPower

Project	Volume of work					
	2011	2012	2013	2014	2015	Total
Pole replacements (FC148) – subtransmission (poles)	11	11	11	11	12	56
Pole replacements (FC148) – HV (poles)	44	45	46	48	49	231
Pole replacements (FC148) – LV (poles)	109	112	115	118	121	574
Pole replacements (FC148) – pole and stay (poles)	12	13	13	13	14	65
Pole replacements (FC149) – staked (poles)	255	260	265	270	275	1325
Crossarm replacements (FC155) (crossarms)	700	700	700	800	800	3700
HV overhead conductor replacements (km)	2.5	2.5	2.5	2.5	2.5	12.5
LV overhead conductor replacements (km)	0.5	0.5	0.5	0.5	0.5	2.5

Source: CitiPower, *Response to information requested 19 October 2010*, 19 October 2010.

[357] CitiPower, *Revised regulatory proposal*, pp. 249, 309.

The AER accepted the projects listed in table P.37 as part of its draft decision.

CitiPower's further comments in respect of the AER's draft decision are discussed below.

- CitiPower considered it would not be able to complete all of the noise works as proposed in its initial regulatory proposal if the AER made its final decision consistent with its draft decision.[358]

  The AER requested CitiPower to explain the basis on which it made the above comment and to advise the AER whether any other proposed environmental, safety and legal capex projects were also unlikely to be completed. In its response, CitiPower:[359]

  - stated it would not be able to complete the proposed noise works because of the reduced allowance (relative to CitiPower's initial regulatory proposal) approved in the AER's draft decision

  - did not state whether any other initially proposed environmental, safety and legal capex projects would similarly not be completed in the forthcoming regulatory control period.

  The AER recognises that complying with all applicable regulatory obligations or requirements associated with the provision of standard control services is a capex objective. CitiPower's revised regulatory proposal did not submit amounts higher than the AER's draft decision and, therefore, the AER considers its draft decision is consistent with forecast expenditure that reasonably reflects the capex criteria.

- CitiPower considered that, should a DNSP require capex to comply with an obligation, that DNSP should demonstrate that its proposed capex is the lowest means of achieving compliance.

  The AER recognises that complying with all applicable regulatory obligations or requirements associated with the provision of standard control services is a capex objective and agrees with CitiPower that a DNSP should demonstrate that its proposed capex is the lowest means of achieving compliance.

- CitiPower considered that the plans submitted under the Electrical Safety Management Regulations should be addressed by the AER as a nominated pass through.

  The AER does not accept that the plans submitted under the Electrical Safety Management Regulations should be a nominated pass through. Section 16.6.4 at chapter 16 of this final decision sets out the items which the AER considers would be included as a nominated pass through. The AER considers that environmental, safety and legal capex projects required to comply with all applicable regulatory obligations or requirements and currently enacted legislation which CitiPower reasonably expects to undertake in the forthcoming regulatory control period

[358] CitiPower, *Initial regulatory proposal*, pp. 119–120; CitiPower, *Revised regulatory proposal*, p. 310.

[359] CitiPower, *Response to information requested 17 August 2010*, 26 August 2010.

would have been included in the revised regulatory proposal. Therefore, any new projects required in the forthcoming regulatory control period as a result of the enactment of new legislation or regulatory obligations would be considered under the regulatory pass through event category.

Table P.38 sets out CitiPower's revised environmental, safety and legal capex proposal and the AER's final decision.

Table P.38 Environmental, safety and legal capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower revised regulatory proposal	1.1	1.1	1.1	1.1	1.1	5.5
AER final decision	5.6	5.8	5.7	6.1	6.2	29.4

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.4.5.4 Powercor

Powercor stated it did not contest the AER's draft decision with respect to environmental, safety and legal capex, however, it considered the AER should include 2009 actual data in its trend analysis and in forecasting the environmental, safety and legal capex required in the forthcoming regulatory control period by reference to historical expenditure.[360] The AER has included 2009 actual data in its analysis.

Following the draft decision, the AER requested the assistance of ESV in consultation with the Victorian DNSPs, in assessing whether there was a primarily safety-driven need for the Victorian DNSPs' proposed works and the associated works volumes in the forthcoming regulatory control period. Meetings were held between ESV and each of the Victorian DNSPs to discuss these matters. Powercor did not submit to ESV in respect of its environmental, safety and legal capex works in the forthcoming regulatory control period.

However, in assessing Powercor's proposed reliability and quality maintained capex, the AER identified the works programs, as set out at table P.39, which are primarily safety-driven and need to be undertaken by Powercor in the forthcoming regulatory control period. These work programs have been included in the AER's final decision on Powercor's environmental, safety and legal capex. Further, as safety considerations are the primary driver of the need for these projects in the forthcoming regulatory control period, ESV will monitor Powercor's completion of these works.

[360] Powercor, *Revised regulatory proposal*, pp. 239, 297.

Table P.39 Proposed reliability and quality maintained capex projects identified by the AER as being primarily safety driven—Powercor

Project	Volume of work					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Pole replacements (FC148) – subtransmission (poles)	64	65	67	69	71	336
Pole replacements (FC148) – HV (poles)	628	645	662	680	697	3312
Pole replacements (FC148) – LV (poles)	200	206	211	217	222	1056
Pole replacements (FC148) – pole and stay (poles)	18	19	19	20	20	96
Pole replacements (FC149) – staked (poles)	902	927	952	977	1002	4760
Crossarm replacements (FC155) (crossarms)	3200	3200	3200	3200	3200	16000
Subtransmission overhead conductor replacements (km)	20.0	20.0	20.0	20.0	20.0	100
HV overhead conductor replacements (km)	460.0	480.0	480.0	480.0	480.0	2380
LV overhead conductor replacements (km)	4.0	4.0	4.0	4.0	4.0	20

Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.

The AER has applied the project unit costs set out at table P.36 to the overhead conductor replacement projects listed at table P.39. The other projects were accepted by the AER as part of its draft decision.

Powercor's further comments in respect of the AER's draft decision are discussed below. The AER's response to the other issues raised by Powercor are set out below.

- Powercor considered it would not be able to complete all of the noise works as proposed in its initial regulatory proposal if the AER made its final decision consistent with its draft decision.[361]

  The AER requested Powercor to explain the basis on which it made the above comment and to advise the AER whether any other proposed environmental, safety and legal capex projects were also unlikely to be completed. In its response, Powercor:[362]

[361] Powercor, *Initial regulatory proposal*, pp. 113–114; Powercor, *Revised regulatory proposal*, p. 298.

[362] Powercor, *Response to information requested 17 August 2010*, 26 August 2010.

    - stated it would not be able to complete the proposed noise works because of the reduced allowance (relative to Powercor's initial regulatory proposal) approved in the AER's draft decision

    - did not state whether any other initially proposed environmental, safety and legal capex projects would similarly not be completed in the forthcoming regulatory control period.

  The AER recognises that complying with all applicable regulatory obligations or requirements associated with the provision of standard control services is a capex objective. Powercor's revised regulatory proposal did not submit amounts higher than the AER's draft decision and, therefore, the AER considers its draft decision is consistent with forecast expenditure that reasonably reflects the capex criteria.

- Powercor considered that, should a DNSP require capex to comply with an obligation, that DNSP should demonstrate that its proposed capex is the lowest means of achieving compliance.

  The AER recognises that complying with all applicable regulatory obligations or requirements associated with the provision of standard control services is a capex objective and agrees with Powercor that a DNSP should demonstrate that its proposed capex is the lowest means of achieving compliance.

- Powercor considered that the plans submitted under the Electrical Safety Management Regulations should be addressed by the AER as a nominated pass through.

  The AER does not accept that the plans submitted under the Electrical Safety Management Regulations should be as a nominated pass through. Section 16.6.4 at chapter 16 of this final decision sets out the items which the AER considers would be included as a nominated pass through. The AER considers that environmental, safety and legal capex projects required to comply with all applicable regulatory obligations or requirements and currently enacted legislation which Powercor reasonably expects to undertake in the forthcoming regulatory control period would have been included in the revised regulatory proposal. Therefore, any new projects required in the forthcoming regulatory control period as a result of the enactment of new legislation or regulatory obligations would be considered under the regulatory pass through event category.

Table P.40 sets out Powercor's revised environmental, safety and legal capex proposal and the AER's final decision.

Table P.40 Environmental, safety and legal capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor revised regulatory proposal	6.5	6.5	6.5	6.5	6.5	32.3
AER final decision	40.5	41.5	41.7	41.9	42.1	207.8

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.

Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.4.5.5 JEN

Following the draft decision, the AER requested the assistance of ESV in consultation with the Victorian DNSPs, in assessing whether there was a primarily safety-driven need for the Victorian DNSPs' proposed works and the associated works volumes in the forthcoming regulatory control period. Meetings were held between ESV and each Victorian DNSP to discuss these matters. JEN made submissions to ESV to establish the scope and volume of environmental, safety and legal capex works supported by ESV as being primarily safety-driven and therefore must be undertaken by JEN in the forthcoming regulatory control period.[363] As discussed at section 8.6.2, the AER has been informed by ESV's recommendations on this matter and notes that completion of the safety-driven project works described will be monitored by ESV. The relevant projects and associated work programs are set out at table P.41.

[363] JEN, *Revised regulatory proposal*, p. 168.

Table P.41 Environmental, safety and legal capex projects supported by ESV—JEN

Project	Volume of work					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Planned non-preferred service replacement (services)	6,000	6,000	6,000	6,000	6,000	30,000
Height replacement – non-preferred service replacement (services)	1,482	1,482	341	341	341	3,987
Identification and removal of public lighting switch wire (spans)	–	1,274	1,700	1,700	426	5,100
Replace existing SWER lines with 22 kV overhead bare conductor (km)	13 km of existing SWER to be replaced in the forthcoming regulatory control period					13
Install GFN and associated equipment at zone substations (zone substations)	3 GFNs to be installed in the forthcoming regulatory control period					3
Replace crossarms/insulator sets – pole top fire mitigation (number replaced)	567	567	567	567	567	2,835
Replace crossarms – based on age and condition (number replaced)	14,117 crossarms to be replaced in the forthcoming regulatory control period					14,117
Replace poles – based on age and condition (number replaced)	1,294 poles to be replaced in the forthcoming regulatory control period					1,294
Stake poles – based on age and condition (number replaced)	1,114 poles to be staked in the forthcoming regulatory control period					1,114
Replace undersized poles (number replaced)	1,385 undersized poles to be replaced in the forthcoming regulatory control period					1,385
Stake undersized poles (number replaced)	1,100 undersized poles to be staked in the forthcoming regulatory control period					1,100
Replace overhead conductor – mainly steel (km)	112 km of overhead conductor (mainly steel) to be replaced in the forthcoming regulatory control period					112
Service line clearance – overhead services requiring relocation (services)	1260	1260	57	57	57	2691
Service line clearance – overhead services requiring undergrounding (services)	315	315	14	14	14	672

Source: ESV, *Assessment by Energy Safe Victoria of EDPR Safety-Related Programs,* Ver 2.0, 18 October 2010, pp. 6–14.

The AER has applied the project unit costs set out at table P.36 to the projects listed at table P.41.

Further, JEN stated that the capex objectives and capex criteria are forward-looking and it requested the AER consider this when making its final determination.[364] As discussed in the introduction to chapter 8, the AER has assessed JEN's environmental, safety and legal capex category as part of determining whether it is satisfied the total of JEN's proposed forecast capital expenditure reasonably reflects the capex criteria. However, where there has been no change to the legal and regulatory obligations faced by the DNSP, the AER considers that historical capex can be used to approximate the future capex requirement.

In coming to its draft decision, the AER had considered information in JEN's Network Asset Management Plan (NAMP) 2010–2015, asset management plans and risk assessment spreadsheets as submitted by JEN in support of its capex proposal.[365] As JEN's revised regulatory proposal reinstated the environmental, safety and legal capex amounts as per its initial regulatory proposal, the AER reconsidered the information previously considered as described above. The AER also considered the documents prepared since November 2009 and provided by JEN at appendices 8.30 to 8.36 inclusive of its revised regulatory proposal.[366]

In its revised regulatory proposal, JEN stated that the AER did not examine in detail the projects included in JEN's environmental, safety and legal capex category.[367] The AER accepts that its draft decision did not provide a line-by-line acceptance/rejection of each of JEN's proposed environmental, safety and legal capex programs/projects and has therefore provided such a list in this final decision at table P.42.

[364] ibid., p. 165.

[365] JEN, *Network Asset Management Plan (NAMP) 2010–2015*, 30 November 2010; JEN, *JEN Response to Nuttall Consulting Information Requests dated 18 Jan 2010 – Item 9*, 30 January 2010, JEN, *JEN Response to information requested 4 March 2010*, 5 March 2010.

[366] JEN, *Revised regulatory proposal*, p. 167.

[367] JEN, *Revised regulatory proposal–Appendix 7.2 JEN Step changes*, 20 July 2010, p. 43.

Table P.42 Environmental, safety and legal capex proposed projects—JEN

Proposed program/project	Description	AER comment
CMEN	Existing program—Practical program completion by June 2011. Rollout of CMEN schemes for high risk, well frequented areas across 24 zone substations on the network.[368]	Not accepted by AER Ongoing/continuing activity–not a step change – Practical program completion by June 2011
Voltage regulator installation	New program —Installation of low voltage voltage regulators	Work volumes as per ESV recommendation
Pole mounted capacitor bank	New program—Installation of fixed pole mounted capacitor banks to cover minimum reactive demand on each feeder	Transferred to reinforcement capex
Distribution substation augmentation–supply quality	New program—Installation of fixed pole mounted capacitor banks to improve power quality.	Transferred to reinforcement capex
Zone substation capacitor bank	New program—Installation of capacitor banks at zone substations to improve power factor.	Transferred to reinforcement capex
Oil containment	Ongoing program—Construction of bunds to reduce risk of escape of oil from power transformers at zone substations.	Not accepted by AER Ongoing/continuing activity–not a step change
Neutral earthing resistor (NER)	Existing program—Program completion by June 2011.	Not accepted by AER Ongoing/continuing activity–not a step change – Program completion by June 2011
Ground fault neutraliser (GFN)	New program—Installation of GFN at new zone substations and upgrade zone substation transformer earthing from direct and NER earthing.	Work volumes as per ESV recommendation
Non-preferred service replacement	New program—Annual replacement of 6,000 neutral screened services from 2011 onwards until all non-preferred services have been replaced.	Work volumes as per ESV recommendation
Public lighting switch wire removal	New program—Opportunistic removal of public lighting switch wire.	Work volumes as per ESV recommendation

368 JEN, *Network Asset Management Plan (NAMP) 2010–2015*, 30 November 2010, pp. 53–54.

SWER replacement	New program—Upgrading of SWER lines in bushfire areas to 2 or 3-phase conductor or underground or insulated conductor, where appropriate.[369]	Work volumes accepted as per ESV recommendation
Transformer mounting height	Existing program—Achieve compliance with ground clearance requirements over the next 40 years on a prioritised basis.[370]	Not accepted by AER Ongoing/continuing activity–not a step change
Cable duct cover replacement	New program—Replacement of cable duct covers in zone substations.[371]	Work volumes as per ESV recommendation
Capacitor bank enclosure replacement	New program—Replacement of rusted mesh on capacitor bank enclosures in zone substations.[372]	Work volumes as per ESV recommendation
Zone substation fence replacement	Existing program.	Not accepted by AER Ongoing/continuing activity–not a step change
Earth grid upgrade	Ongoing program—Replacement of earthing system subject to comply with safety criteria.[373]	Not accepted by AER Ongoing/continuing activity–not a step change
Substation security	Ongoing program.	Not accepted by AER Ongoing/continuing activity–not a step change
Supply quality/reliability–LV overhead augmentation	—	Transferred to reinforcement capex
Protection setting review	New program— proposed as an 'opex-step change' item in JEN's initial regulatory proposal.[374]	Work volumes as per ESV recommendation
HV and LV ABC relocation, underground – new electricity line	New program—proposed as an 'opex-step change' item in JEN's initial regulatory proposal.[375]	Work volumes as per ESV recommendation

369 ibid., p. 68.
370 ibid., p. 52.
371 ibid., p. 54.
372 ibid., pp. 54,141.
373 ibid., pp. 127–128.
374 JEN, *Response to information requested 7 September 2010*, 10 September 2010.
375 ibid..

clearance regulation						

Source: JEN, *JEN Response to Nuttall Consulting Information Requests dated 18 Jan 2010 – Item 9*, 30 January 2010; JEN, *JEN Attachment 1 – 150210 JEN ESL Overview Presentation.pdf*, 3 March 2010; JEN, *Response to information requested 7 September 2010*, 10 September 2010.

As set out at table P.42, the AER considers that the pole mounted capacitor bank and zone substation capacitor bank projects along with supply quality/reliability LV overhead augmentation projects are more appropriately categorised as reinforcement capex because, although the proposed projects should improve network power factor, they ultimately result in augmentation of network capacity.[376] Therefore, these projects have been transferred to reinforcement capex and assessed as part of that capex category.

Table P.43 sets out JEN's revised environmental, safety and legal capex proposal and the AER's final decision.

Table P.43 Environmental, safety and legal capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN revised regulatory proposal	6.3	8.3	6.0	4.7	4.5	30.0
AER final decision	16.4	16.6	14.4	14.4	14.2	76.1

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.4.5.6 SP AusNet

SP AusNet adopted the allowance set out in the AER's draft decision because it considered the AER's allowance of $5.5 million ($, 2010) was consistent with its own forecast total capex requirement for:[377]

- environmental, bunding, security
- occupational health and safety – replacement of current transformers
- occupational health and safety – replacement of disconnectors
- occupational health and safety – replacement of silicon carbide gap arrestors.

However, following the draft decision, the AER requested the assistance of ESV in consultation with the Victorian DNSPs, in assessing whether there was a primarily safety-driven need for the Victorian DNSPs' proposed works and the associated works volumes in the forthcoming regulatory control period. Meetings were held between ESV and each of the Victorian DNSPs to discuss these matters. SP AusNet made submissions to ESV to establish the scope and volume of environmental, safety and legal capex works supported by ESV as being primarily safety-driven and therefore

[376] JEN, *Network Asset Management Plan (NAMP) 2010–2015*, 30 November 2010, pp. 101–102.
[377] SP AusNet, *Revised regulatory proposal*, pp. 137–138.

must be undertaken by SP AusNet in the forthcoming regulatory control period. As discussed at section 8.6.2, the AER has been informed by ESV's recommendations on this matter and notes that completion of the safety-driven project works described will be monitored by ESV.

The relevant projects and associated work programs are set out at table P.44.

Table P.44 Environmental, safety and legal capex projects— safety-driven projects— SP AusNet

Project	Volume of work					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Crossarm replacement (number replaced)	9357	9357	9357	9357	9357	46,785
Pre-emptive replacement of steel conductor (km)	621	259	544	228	119	1,771
Pre-emptive replacement of copper conductor (km)	40	114	66	39	25	284
Replace HV pin type insulator sets – pole top fire mitigation (number replaced)	1130	1130	1130	1130	1130	5,650
Targeted replacement of EDOs (number replaced)	1908	2027	2156	2292	2442	10,825
Targeted bird and animal proofing in high bushfire risk areas (number of assets)	1200	1200	1200	1200	1200	6,000
Replace all SWER OCRs (number replaced)	47	94	116	131	137	525
Replace/upgrade 3-phase ACR controllers (number replaced/upgraded)	21	42	51	59	61	234
Augment spans – habitat trees (spans)	2000 spans to be augmented (undergrounded/relocated/replaced with ABC) in the forthcoming regulatory control period					2,000

Source: ESV, *Assessment by Energy Safe Victoria of EDPR Safety-Related Programs*, Ver 2.0, 18 October 2010, pp. 22–25; SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010; AER assessment of reliability and quality maintained capex.

The AER has applied the project costs set out at table P.36 in respect of the projects listed at table P.44.

Table P.45 sets out SP AusNet's revised environmental, safety and legal capex proposal and the AER's final decision.

Table P.45 Environmental, safety and legal capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet revised regulatory proposal	1.1	1.1	1.1	1.1	1.1	5.3
AER final decision	39.5	38.9	45.7	43.2	44.8	212.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.

Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.4.5.7 United Energy

In coming to its draft decision, the AER had considered information in United Energy's Asset Management Plan 2009–2016, asset management plans and risk assessment spreadsheets as submitted by United Energy in support of its capex proposal.[378]

Following the draft decision, the AER requested the assistance of ESV in consultation with the Victorian DNSPs, in assessing whether there was a primarily safety-driven need for the Victorian DNSPs' proposed works and the associated works volumes in the forthcoming regulatory control period. Meetings were held between ESV and each of the Victorian DNSPs to discuss these matters. United Energy made submissions to ESV to establish the scope and volume of environmental, safety and legal capex works supported by ESV as being primarily safety-driven and therefore must be undertaken by United Energy in the forthcoming regulatory control period. As discussed at section 8.6.2, the AER has been informed by ESV's recommendations on this matter and notes that completion of the safety-driven project works described will be monitored by ESV.

Further, in assessing United Energy's proposed reliability and quality maintained capex, the AER identified the works programs, which are primarily safety-driven and need to be undertaken by United Energy in the forthcoming regulatory control period. These work programs have been included in the AER's final decision on United Energy's environmental, safety and legal capex and, as safety considerations are the primary driver of the need for these projects in the forthcoming regulatory control period, ESV will monitor United Energy's completion of these works.

The relevant projects and associated work programs are set out at table P.46.

[378] United Energy, *UED Response to Nuttall Consulting Information Requests dated 18 Jan 2010 – Item 9*, 2 February 2010.

Table P.46 Environmental, safety and legal capex projects— safety-driven projects—United Energy

Project	Volume of work					
	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Planned non-preferred service replacement (services)	26,000	26,000	31,000	31,000	30,000	144,000
Height replacement – non-preferred service replacement (services)	4,983	4,983	884	884	884	12,618
Identification and removal of public lighting switch wire (spans)	–	2,412	2,412	2,412	–	7,236
Replace existing SWER lines with 22 kV overhead bare conductor (km)	44km of existing SWER to be replaced in the forthcoming regulatory control period					44
Install GFN and associated equipment at zone substations (zone substations)	7 GFNs to be installed in the forthcoming regulatory control period					7
Replace crossarms – pole top fire mitigation (number replaced)	3,000 crossarms to be replaced (for fire mitigation) in the forthcoming regulatory control period					3,000
Replace sets of insulators – pole top fire mitigation (number replaced)	3,400 insulator sets to be replaced in the forthcoming regulatory control period					3,400
Inspections, cleaning, tightening, life extension – pole top fire mitigation (number)	3,300 pole top structures to be inspected/cleaned in the forthcoming regulatory control period					3,300
Replace crossarms – based on age and condition (number replaced)	50,088 crossarms to be replaced in the forthcoming regulatory control period					50,088
Pole top structure - HV fuse replacement	174	174	274	72	114	808
Pole top structure - surge diverter replacement	236	236	236	146	200	1,054
Install HV ABC in high bushfire risk areas (metres)	4,800	4,800	4,800	4,800	4,800	24,000
Install LV ABC in high bushfire risk areas (metres)	2,950	2,950	2,950	2,950	2,950	14,750
Replace poles – based on age and condition (number replaced)	2,805 poles to be replaced in the forthcoming regulatory control period					2,805
Stake poles – based on age and condition (number replaced)	2,098 poles to be staked in the forthcoming regulatory control period					2,098
Replace overhead steel conductors in high bushfire risk areas (km)	80km of overhead steel conductors in high bushfire risk areas to be replaced in the forthcoming regulatory control period					80

Replace other conductors in high bushfire risk areas (km)	126km of other conductors in high bushfire risk areas to be replaced in the forthcoming regulatory control period					126
Install backup protection schemes (zone substations)	3	3	3	3	3	15
Service line clearance – overhead services requiring relocation (services)	3,318	3,318	149	149	149	7083
Service line clearance – overhead services requiring undergrounding (services)	830	830	37	37	37	1771
Overhanging trees capex (underground, line relocation, ABC etc) – High bushfire risk area (spans)	700 spans to be undergrounded/relocated/replaced with ABC in high bushfire risk areas in the forthcoming regulatory control period					700
Overhanging trees capex (underground, line relocation, ABC etc) – Low bushfire risk area (spans)	28 spans to be undergrounded/relocated/replaced with ABC in low bushfire risk areas in the forthcoming regulatory control period					28

Source: ESV, *Assessment by Energy Safe Victoria of EDPR Safety-Related Programs*, Ver 2.0, 18 October 2010, pp. 14–21; United Energy, *Revised regulatory proposal*, Appendix B-4, July 2010; AER assessment of reliability and quality maintained capex.

The AER has applied the project unit costs set out at table P.36 to the projects listed at table P.46.

In coming to its draft decision, the AER had considered information in United Energy's Asset Management Plan 2009–2016, asset management plans and risk assessment spreadsheets as submitted by United Energy in support of its capex proposal. As United Energy's revised regulatory proposal reinstated the environmental, safety and legal capex amounts as per its initial regulatory proposal, the AER reconsidered the information previously considered as described above. United Energy did not provide any additional documents relating to environmental, safety and legal capex as part of its revised regulatory proposal. However, United Energy confirmed to the AER that the individual projects proposed in the environmental, safety and legal capex category had not changed between its initial and revised regulatory proposals.[379]

Although the AER's draft decision did not provide a line-by-line acceptance/rejection of each of United Energy's proposed environmental, safety and legal capex programs/projects, the AER has provided such a list in this final decision at table P.47.

379 United Energy, *Response to information requested 7 September 2010*, 15 September 2010.

Table P.47 Environmental, safety and legal capex proposed projects—United Energy

Proposed program/project	Description	AER comment
Distribution transformer mounting height	Existing program— replacement of transformers on a prioritised basis to achieve compliance with ground clearance requirements by 2042–2043.[380]	Not accepted by AER Ongoing/continuing activity–not a step change
Public lighting switch wire removal	New program—opportunistic removal of public lighting switch wire.[381]	Work volumes as per ESV recommendation
Zone substation minor building works	Existing program—repair and refurbish buildings based on civil and structural inspections.[382]	Not accepted by AER Ongoing/continuing activity–not a step change
Zone substation security upgrades	Existing program—upgrade security to deter unauthorised access.[383]	Not accepted by AER Ongoing/continuing activity–not a step change
Doncaster pillar earthing facilities	New program—replacement of pillars in Doncaster area to address reliability and safety issues.[384]	Work volumes as per ESV recommendation
Zone substation oil containment	Ongoing program—containment of oil leaks from zone substation transformers.[385]	Not accepted by AER Ongoing/continuing activity–not a step change
Ground fault neutraliser (GFN)	New program—Installation of GFN at new zone substations and upgrade zone substation transformer earthing from direct and NER earthing.[386]	Work volumes as per ESV recommendation
Backup earth fault protection	New program—Installation of backup earth fault protection schemes at 15 zone substations during 2010–2015.[387]	Work volumes as per ESV recommendation

380 United Energy, *Asset Management Plan 2009–2016*, Version 1.0 Final For Review, Undated, pp. 176, 261.
381 ibid., pp. 256, 264.
382 ibid., pp. 147, 154, 269–270.
383 ibid., pp. 269–270.
384 ibid., p. 173.
385 ibid., pp. 148, 245.
386 ibid., pp. 265, 276.
387 ibid., p. 162.

Zone substation building refurbishment	Existing program—repair and refurbish buildings based on civil and structural inspections.[388]	Not accepted by AER Ongoing/continuing activity–not a step change
Noise mitigation	Existing program—noise reduction works at zone substations.[389]	Not accepted by AER Ongoing/continuing activity–not a step change

Source: United Energy, *UED Response to Nuttall Consulting Information Requests dated 18 Jan 2010 – Item 9*, 2 February 2010; United Energy, *Asset Management Plan 2009–2016*, Version 1.0 Final For Review, Undated.

Table P.48 sets out United Energy's revised environmental, safety and legal capex proposal and the AER's final decision.

Table P.48 Environmental, safety and legal capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy revised regulatory proposal	21.7	14.9	12.8	9.6	9.1	68.1
AER final decision	44.4	44.8	40.6	39.8	39.5	209.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.

Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.4.6 AER conclusion

This section P.4has assessed the direct costs of the proposed allowance for environmental, safety and legal capex which is one component of each Victorian DNSP's proposed total forecast capital expenditure. The AER considers that the direct costs determined in this section P.4 are consistent with the requirement in clause 6.5.7(c) of the NER that the forecast capital expenditure reasonably reflects the capital expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each Victorian DNSP's total forecast capital expenditure.

That constituent decision, which should be read together with this appendix, is discussed at chapter 8.

Table P.49 sets out the AER's conclusion on the direct cost of each Victorian DNSP's revised regulatory proposals on environmental, safety and legal capex which it

388 ibid., pp. 147, 154, 269–270.
389 ibid., pp. 148, 246–247.

considers is consistent with forecast capital expenditure that reasonably reflects the capex criteria.

As explained at the beginning of this section P.4, in coming to this view, the AER has assessed the information submitted in support of each Victorian DNSP's revised regulatory proposals on environmental, safety and legal capex, having regard to the capex factors. Where relevant, the AER has made the minimum necessary change to the Victorian DNSPs' forecast environmental, safety and legal capex.

Table P.49 AER conclusion— Victorian DNSPs' 2011–15 environmental, safety and legal capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	5.6	5.8	5.7	6.1	6.2	29.4
Powercor	40.8	41.7	41.9	42.1	42.4	208.9
JEN	16.4	16.6	14.4	14.4	14.2	76.1
SP AusNet	39.5	38.9	45.7	43.2	44.8	212.2
United Energy	44.4	44.8	40.6	39.8	39.5	209.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes margins, overheads and real cost increases.

P.5 SCADA and network control

This section considers the Victorian DNSPs' proposals on the SCADA and network control capex category.

As noted at the beginning of the capex chapter (chapter 8) of this final decision, each Victorian DNSP proposed allowances for SCADA and network control capex, as a component of its total proposed forecast capital expenditure for the 2011–15 regulatory control period. The assessment of this component is relevant to determining whether the AER is satisfied that the total proposed forecast capital expenditure or its estimate of the required capital expenditure reasonably reflects the capital expenditure criteria.

Specifically, this section assesses the proposed allowances and what the level of efficient direct cost expenditure for SCADA and network control capex which a prudent operator, in the circumstances of each Victorian DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capital expenditure objectives.

Therefore, this section gives the reasons for the AER's final decision in respect of the direct costs relating to the Victorian DNSPs' respective revised regulatory proposals on SCADA and network control capex.

That is, in accordance with NER cl.6.12.2, this appendix sets out the basis and rationale for the AER's final decision including:[390]

- details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the AER
- the values adopted by the AER for the input variable in any calculations and formulae, including:
  - whether those values have been taken or derived from the Victorian DNSP's initial or revised regulatory proposals, and
  - if not, the rationale for the adoption of those values
- details of any assumptions made by the AER in undertaking any material and quantitative analyses
- reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretions, as referred to in chapter 6 of the NER, for the purposes of the AER's final decision.

Approach

Where a Victorian DNSP accepted the AER's draft decision on the direct costs for the SCADA and network control capex, the AER has approved that same direct cost amount(s) in its final decision.

Where a Victorian DNSP did not accept the AER's draft decision on the SCADA and network control capex direct costs, the AER has considered whether the revised regulatory proposal in respect of that proposed capex reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant Victorian DNSP would require to meet the capex objectives.

That is, having regard to the capex factors set out at NER cl.6.5.7(e), and particularly:

- the information included in or accompanying the building block proposal
- submissions received in the course of consulting on the building block proposal
- analysis undertaken by or for the AER and published before the distribution determination is made in its final form
- benchmark capital expenditure that would be incurred by an efficient distribution DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods

the AER has considered whether the proposed projects are in accordance with good industry practice including whether:

[390] NER, clause 6.12.2.

- there is a justifiable need for the proposed capex
- the proposed projects have been objectively and competently analysed to a standard that is consistent with good industry practice
- the proposed projects align with strategic capex plans and policies.

The AER sought explanation of the drivers of any proposed step changes in the SCADA and network control capex. The historical underlying trend in expenditure in the SCADA and network control capex was used as the starting point to assess whether a step change (increase or decrease) in expenditure had been proposed. However, given that the historical trend cannot completely determine future requirements, the AER requested the Victorian DNSPs to provide relevant economic analysis which clearly demonstrated the need to undertake the proposed projects in the forthcoming regulatory control period. The AER expected the analysis would demonstrate how engineering judgements had been translated into step changes in expenditure and be supported by cost-benefit analysis including options analysis. Having said that, the AER also expected the analysis would be appropriate in respect of the materiality of the proposed project expenditures as a proportion of the total capex for SCADA and network control.

The AER must allow each Victorian DNSP adequate funding to recover at least its respective efficient costs of providing direct control services. The AER is also aware that each Victorian DNSP must also satisfy safety and other regulatory and legislative obligations while managing its respective networks in accordance with good electricity practices. Therefore, in assessing each Victorian DNSP's proposed expenditures in SCADA and network control capex, the AER considered:

- whether the proposed projects aligned with strategic capex plans and policies
- changes in timing have been considered to ensure prudent decision-making
- processes or systems for project approval reflected good governance and business practices for undertaking capital projects
- cost-estimating processes incorporate feed-back from specific experience.

Where the AER has not accepted a Victorian DNSP's revised regulatory proposal, in respect of the direct costs of projects proposed in SCADA and network control capex, the AER has made the minimum necessary change to the Victorian DNSP's forecast capex direct cost expenditure.

The AER's assessment and final decision on a realistic expectation of the demand forecast and costs inputs required to achieve the capex objectives are set out at chapter 5 and appendix K respectively of this final decision. The AER's final decision on the total capex reasonably required by each Victorian DNSP is set out at chapter 8 and includes amounts for the direct costs (as set out in this appendix) for SCADA and network control capex, as adjusted for overheads, real cost increases and margins.

P.5.1 AER draft decision

The AER considered that the Victorian DNSPs appear to spend significantly less than forecast and that actual capex tends to follow a gradually increasing trend. Therefore, the historical underlying trend of capex was used by the AER as the starting point for assessing the reasonableness of the proposed SCADA and network control capex. In identifying the underlying trend, the AER considered data for the years 2004 to 2008 inclusive. The 2009 and 2010 data provided by the Victorian DNSPs was considered to be forecast data and therefore not considered to be part of the historical trend.

The AER recognised that the Victorian DNSPs retained discretion to prioritise their work programs and allocate their resources to meet customer requirements while managing and operating their networks in accordance with good electricity industry practice. That is, the Victorian DNSPs had at times over or underspent relative to the ESCV benchmark allowance on the basis of their own assessments of whether it was efficient to do so.

P.5.1.1 CitiPower

The AER noted that CitiPower and Powercor jointly commenced implementation of a new SCADA system platform during 2006–2010. The AER reviewed the Network Protection and Control Communications Strategy 2009–14 and noted that indicative program costs and benefits were not quantified and there was no economic assessment of the program scope and timing.

The AER considered that CitiPower had not justified its SCADA and network control capex requirement in the forthcoming regulatory control period. Therefore, the AER did not accept CitiPower's proposed capex amounts and substituted amounts based on a continuation of the historical expenditure trend in this capex category.

Table P.50 sets out CitiPower's initial proposed SCADA and network control capex and the AER's draft decision.

Table P.50 SCADA and network control capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower initial regulatory proposal	3.8	3.5	3.6	3.6	3.6	18.1
AER draft decision	1.0	1.0	1.0	1.0	0.9	4.9

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 406, 413.

P.5.1.2 Powercor

The AER noted that CitiPower and Powercor jointly commenced implementation of a new SCADA system platform during 2006–2010. The AER reviewed the Network Protection and Control Communications Strategy 2009–14 and noted that indicative program costs and benefits were not quantified and there was no economic assessment of the program scope and timing.

The AER considered that Powercor had not justified its SCADA and network control capex requirement in the forthcoming regulatory control period. Therefore, the AER did not accept Powercor's proposed capex amounts and substituted amounts based on a continuation of the historical expenditure trend in this capex category.

Table P.51 sets out Powercor's initial proposed SCADA and network control capex and the AER's draft decision.

Table P.51 SCADA and network control capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor initial regulatory proposal	5.9	6.3	6.3	6.1	6.0	30.6
AER draft decision	2.5	2.5	2.4	2.4	2.3	12.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 406, 413.

P.5.1.3 JEN

JEN proposed expenditures relating to integration of an electronic zone substation security system with its SCADA system. The AER noted the project was part of a larger continuing program consistent with JEN's strategy to improve security at its zone substations and the AER accepted JEN's proposed capex amounts.

Table P.52 sets out JEN's initial proposed SCADA and network control capex and the AER's draft decision.

Table P.52 SCADA and network control capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN initial regulatory proposal	0.7	1.0	1.1	0.3	0.0	3.1
AER draft decision	0.7	1.1	1.1	0.3	0.0	3.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 406, 413.

P.5.1.4 SP AusNet

SP AusNet proposed expenditures to upgrade its SCADA master station IT hardware and software. The AER noted the project had been included in SP AusNet's Information Technology Strategy and, as a result, considered the relevant costs were also included in the proposed non-network IT capex. Therefore, the AER did not accept SP AusNet's proposed capex amounts and substituted amounts based on the inclusion of the proposed SCADA and network control expenditures in the non-network IT capex category.

Table P.53 sets out SP AusNet's initial proposed SCADA and network control capex and the AER's draft decision.

Table P.53 SCADA and network control capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet initial regulatory proposal	0.6	0.7	1.1	4.1	0.9	7.4
AER draft decision	0.0	0.0	0.0	0.0	0.0	0.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 406, 413.

P.5.1.5 United Energy

United Energy proposed expenditures for the fit-out of new control room facilities. Control room services are currently provided by Jemena Asset Management (JAM). United Energy has taken steps to 'in-source' the provision of the control room services consistent with its transformed business model. The AER did not consider that United Energy had demonstrated that alternative arrangements necessitating the in-sourcing of control room functions will be in place in the forthcoming regulatory control period. Therefore, the AER did not accept United Energy's proposed capex amounts and substituted amounts based on a continuation of the historical expenditure trend in this capex category.

Table P.54 sets out United Energy's initial proposed SCADA and network control capex and the AER's draft decision.

Table P.54 SCADA and network control capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy initial regulatory proposal	0.0	0.7	3.9	0.0	0.0	4.7
AER draft decision	0.0	0.0	0.0	0.0	0.0	0.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 406, 413.

P.5.2 Victorian DNSP revised regulatory proposals

P.5.2.1 CitiPower

CitiPower submitted that the AER should include 2009 actual data in forecasting the SCADA and network control capex in the forthcoming regulatory control period by reference to historical expenditure.[391]

CitiPower also submitted that the AER had not considered the circumstances and risks facing CitiPower in the forthcoming regulatory control period. It described three broad categories of risks which it considered were the drivers of its proposed SCADA and network control programs in the forthcoming regulatory control period:[392]

- maintaining network risks and reliability
- maintaining occupational health and safety in respect of the network and public safety
- ensuring compliance with the Electricity System Code (and the associated HV Protection sub-code), Chapter 5 of the NER and the Distribution Code.

CitiPower also clarified that:[393]

- the proposed implementation of DMS field devices (that is, network data collection field devices) was included in the SCADA and network control capex category
- the deferral of much of its SCADA and network control capex was due to reasons other than efficiency. That is, there were delays in the implementation of the Distribution Management System (DMS) and the alignment of the Geographical Information System (GIS) and Outage Management System (OMS)
- each of its proposed projects was linked to its Network Protection and Control Communications Strategy 2009–2014 document.

CitiPower provided a qualitative summary of the benefits likely to result from its proposed SCADA and network control capex in the forthcoming regulatory control period because it considered that the benefits were difficult to quantify.[394]

Table P.55 sets out the AER's draft decision and CitiPower's revised SCADA and network control capex proposal.

[391] CitiPower, *Revised regulatory proposal*, p. 312.
[392] ibid., p. 313.
[393] ibid., pp. 313–314.
[394] ibid., pp. 317–318.

Table P.55 SCADA and network control capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	1.0	1.0	1.0	1.0	0.9	4.9
CitiPower revised regulatory proposal	3.8	3.4	3.6	3.6	3.6	18.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 413.

P.5.2.2 Powercor

Powercor submitted that the AER should include 2009 actual data in forecasting the SCADA and network control capex in the forthcoming regulatory control period by reference to historical expenditure.[395]

Powercor also submitted that the AER had not considered the circumstances and risks facing Powercor in the forthcoming regulatory control period. It described three broad categories of risks which it considered were the drivers of its proposed SCADA and network control programs in the forthcoming regulatory control period:[396]

- maintaining network risks and reliability
- maintaining occupational health and safety in respect of the network and public safety
- ensuring compliance with the Electricity System Code (and the associated HV Protection sub-code), Chapter 5 of the NER and the Distribution Code.

Powercor also clarified that:[397]

- the proposed implementation of DMS field devices (that is, network data collection field devices) was included in the SCADA and network control capex category
- the deferral of much of its SCADA and network control capex was due to reasons other than efficiency. That is, there were delays in the implementation of the Distribution Management System (DMS) and the alignment of the Geographical Information System (GIS) and Outage Management System (OMS)
- each of its proposed projects was linked to its Network Protection and Control Communications Strategy 2009–2014 document.

395 Powercor, *Revised regulatory proposal*, p. 300.
396 ibid., p. 301.
397 ibid., pp. 302–303.

Powercor provided a qualitative summary of the benefits likely to result from its proposed SCADA and network control capex in the forthcoming regulatory control period because it considered that the benefits were difficult to quantify.[398]

Table P.56 sets out the AER's draft decision and Powercor's revised SCADA and network control capex proposal.

Table P.56 SCADA and network control capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	2.5	2.5	2.4	2.4	2.3	12.0
Powercor revised regulatory proposal	5.8	6.2	6.3	6.1	6.0	30.3

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 413.

P.5.2.3 JEN

JEN noted that the AER had accepted its proposed forecast capex for SCADA and network control.[399]

Table P.57 sets out the AER's draft decision and JEN's revised SCADA and network control capex proposal.

Table P.57 SCADA and network control capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN revised regulatory proposal	0.7	1.0	1.1	0.3	0.0	3.1
AER draft decision	0.6	0.8	1.0	0.3	0.0	2.8

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 413.

P.5.2.4 SP AusNet

SP AusNet submitted that the AER had not understood its initial regulatory proposal and had not undertaken a proper review of SP AusNet's proposal.[400] SP AusNet considered the AER had made an error of fact or had incorrectly applied its discretion by deciding not to accept SP AusNet's forecast SCADA and network control capex.[401]

[398] ibid., pp. 307–308.
[399] JEN, *Revised regulatory proposal*, p. 168.
[400] SP AusNet, *Revised regulatory proposal*, p. 139.
[401] ibid., p. 140.

In particular, SP AusNet submitted that its IT Strategy clearly separated costs relating to non-network IT capex and SCADA and network control capex. SP AusNet objected to determining an allowance for SCADA IT capex on the same basis as non-network IT capex for the reason that it considers SCADA IT capex to be of a "system-critical nature".[402]

Table P.58 sets out the AER's draft decision and SP AusNet's revised SCADA and network control capex proposal.

Table P.58 SCADA and network control capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	0.0	0.0	0.0	0.0	0.0	0.0
SP AusNet revised regulatory proposal	0.6	0.7	1.1	4.1	0.9	7.4

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.

Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 413.

P.5.2.5 United Energy

United Energy submitted that both its initial regulatory proposal and its revised regulatory proposal consisted of two separate components:[403]

- Control Room relocation
- increasing data centre fibre capacity.

United Energy submitted that the AER had failed to consider the data centre fibre capacity as a discrete project and that the AER should consider this project on its own merits separate from the Control Room relocation project.[404] Further, United Energy considered it is at risk of being unable to operate its network and meet its licence obligations if it is unable to create a control centre facility as part of its transformed business model. In support of its view, United Energy stated it has commenced planning for the commercial lease of property and the construction of a new network control centre.[405]

Table P.59 sets out the AER's draft decision and United Energy's revised SCADA and network control capex proposal.

[402] ibid., p. 139.
[403] United Energy, *Revised regulatory proposal*, p. 145.
[404] ibid., p. 145.
[405] ibid., p. 145.

Table P.59 SCADA and network control capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	0.0	0.0	0.0	0.0	0.0	0.0
United Energy revised regulatory proposal	0.0	0.7	0.7	0.0	0.0	1.5

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.
Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15,* Draft decision, June 2010, p. 413.

P.5.3 Submissions

The AER received a submission from the Energy Users Coalition of Victoria (EUCV) on the SCADA and network control capex proposed by the Victorian DNSPs.

The EUCV supported the AER's approach and considered it was "detailed, robust and reflect[ed] the actuality of what the [Victorian DNSPs] themselves considered to be appropriate investment in these areas".[406]

P.5.4 Consultant review

In the case of SCADA and network control capex, Nuttall Consulting assessed only the matters raised in the revised regulatory proposals submitted by CitiPower and Powercor

P.5.4.1 CitiPower

Nuttall Consulting considered that CitiPower's underspend in the SCADA and network control capex category in the 2006–2010 regulatory period represented a prudent level of expenditure.[407] That is, CitiPower had not provided evidence that its expenditure in 2006–2010 was inadequate and resulting in adverse consequences.[408] However, Nuttall Consulting considered that CitiPower's planning processes do not accommodate the impacts of unforeseen project delays or deferrals in forecasting SCADA and network control capex requirements for the forthcoming regulatory control period.[409]

406 Energy Users Coalition of Victoria, *Australian Energy Regulator Victorian Electricity Distribution Revenue Reset AER Draft Decisions and Revised Regulatory Proposals on CitiPower, Jemena, Powercor, SP AusNet and United Energy Applications: A response by Energy Users Coalition of Victoria*, August 2010, p. 22.
407 Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals,* 22 October 2010, pp. 81–83.
408 ibid., pp. 81–83.
409 ibid., pp. 81–83.

DMS field devices

Nuttall Consulting agreed that CitiPower's proposed DMS field devices project should be treated as separate and additional to the DMS projects included in the non-network IT capex category.[410] Although both CitiPower's 2001 and 2006 Electricity Distribution Price Review proposals had identified increasing network utilisation and increasing embedded generation connections as reasons for installation of DMS field devices, Nuttall Consulting noted that CitiPower described the proposed installation of DMS field devices as a new program that would commence in the forthcoming regulatory control period.[411]

In summary, Nuttall Consulting considered that CitiPower had:[412]

- not identified any external obligations or regulations requiring the installation of DMS field devices
- not provided any quantified benefits relating to installation of DMS field devices
- not provided information identifying or quantifying efficiencies or opex trade-offs from the proposed installation of DMS field devices
- not shown that the installation of DMS field devices will provide consumers with a tangible benefit or service improvement
- not shown the proposed expenditure is efficient or required to meet the capex objectives.

Therefore, Nuttall Consulting did not recommend inclusion of the proposed SCADA and network control capex for installation of DMS field devices in the forthcoming regulatory control period.[413] Nuttall Consulting noted that CitiPower's proposed DMS IT project was independent from the project to install DMS field devices.[414]

Strategic plan

Nuttall Consulting agreed that CitiPower's proposed SCADA and network control projects were linked to CitiPower's Network Protection and Control Communications Strategy 2009–2014.[415] Although the strategy document did not discuss capex forecasting or identify possible project delays, Nuttall Consulting considered that the strategy did not represent the efficient level of future capex.[416] That is, Nuttall Consulting considered that CitiPower had a robust and comprehensive capex governance process which would result in rejection or deferral of some projects discussed in the strategy.[417]

Table P.60 sets out Nuttall Consulting's recommendation on SCADA and network control capex for CitiPower in the forthcoming regulatory control period.

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410 ibid., p. 80.
411 ibid., p. 80.
412 ibid., pp. 80–81.
413 ibid., p. 81.
414 ibid., p. 81.
415 ibid., p. 84.
416 ibid., pp. 83–85.
417 ibid., pp. 84–85.

Table P.60 Nuttall Consulting recommendation on CitiPower SCADA and network control capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on CitiPower SCADA and network control capex	0.9	0.9	0.9	0.9	0.9	4.6

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 86.

P.5.4.2 Powercor

Nuttall Consulting considered that Powercor's underspend in the SCADA and network control capex category in the 2006–2010 regulatory period represented a prudent level of expenditure.[418] That is, Powercor had not provided evidence that its expenditure in 2006–2010 was inadequate and resulting in adverse consequences.[419] However, Nuttall Consulting considered that Powercor's planning processes do not accommodate the impacts of unforeseen project delays or deferrals in forecasting SCADA and network control capex requirements for the forthcoming regulatory control period.[420]

DMS field devices

Nuttall Consulting agreed that Powercor's proposed DMS field devices project should be treated as separate and additional to the DMS projects included in the non-network IT capex category.[421] Although both Powercor's 2001 and 2006 Electricity Distribution Price Review proposals had identified increasing network utilisation and increasing embedded generation connections as reasons for installation of DMS field devices, Nuttall Consulting noted that Powercor described the proposed installation of DMS field devices as a new program that would commence in the forthcoming regulatory control period.[422]

In summary, Nuttall Consulting considered that Powercor had:[423]

- not identified any external obligations or regulations requiring the installation of DMS field devices
- not provided any quantified benefits relating to installation of DMS field devices
- not provided information identifying or quantifying efficiencies or opex trade-offs from the proposed installation of DMS field devices

418 ibid., pp. 154–156.
419 ibid., pp. 154–156.
420 ibid., pp. 154–156.
421 ibid., p. 153.
422 ibid., p. 153.
423 ibid., pp. 153–154.

- not shown that the installation of DMS field devices will provide consumers with a tangible benefit or service improvement

- not shown the proposed expenditure is efficient or required to meet the capex objectives.

Therefore, Nuttall Consulting did not recommend inclusion of the proposed SCADA and network control capex for installation of DMS field devices in the forthcoming regulatory control period.[424] Nuttall Consulting noted that Powercor's proposed DMS IT project was independent from the project to install DMS field devices.[425]

Strategic plan

Nuttall Consulting agreed that Powercor's proposed SCADA and network control projects were linked to Powercor's Network Protection and Control Communications Strategy 2009–2014.[426] Although the strategy document did not discuss capex forecasting or identify possible project delays, Nuttall Consulting considered that the strategy did not represent the efficient level of future capex.[427] That is, Nuttall Consulting considered that Powercor had a robust and comprehensive capex governance process which would result in rejection or deferral of some projects discussed in the strategy.[428]

Table P.61 sets out Nuttall Consulting's recommendation on SCADA and network control capex for Powercor in the forthcoming regulatory control period.

Table P.61 Nuttall Consulting recommendation on Powercor SCADA and network control capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on Powercor SCADA and network control capex	2.0	2.0	2.0	2.0	2.0	909

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.

Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 159.

P.5.4.3 JEN

Nuttall Consulting did not assess JEN's revised regulatory proposal on SCADA and network control capex because JEN accepted the AER's draft decision.[429]

424 ibid., p. 154.
425 ibid., p. 154.
426 ibid., p. 156.
427 ibid., pp. 156–158.
428 ibid., pp. 157–158.
429 ibid., p. 119.

P.5.4.4 SP AusNet

Nuttall Consulting did not assess SP AusNet's revised regulatory proposal on SCADA and network control capex because it did not assess SP AusNet's initial regulatory proposal on SCADA and network control capex.[430]

P.5.4.5 United Energy

Nuttall Consulting did not assess United Energy's revised regulatory proposal on SCADA and network control capex because it did not assess United Energy's initial regulatory proposal on SCADA and network control capex.[431]

P.5.5 Issues and AER considerations

P.5.5.1 Use of historical actual expenditure to forecast capex requirement in forthcoming regulatory control period

The AER agrees with the Victorian DNSPs that 2009 data should be used in historical expenditure analysis because audited 2009 regulatory accounts are now available.

P.5.5.2 CitiPower

In its initial regulatory proposal, CitiPower stated it had:

> … started updating its existing protection and control communications infrastructure … [and] is also committed to undertaking new investment in the 2011–15 regulatory control period in order to improve its knowledge of network performance, improve data security, increase data visibility and provide more accurate and timely information to customers on fault rectification.[432]

In its revised regulatory proposal, CitiPower claimed that "[in] assessing its proposed SCADA and network control capex, the AER did not consider the circumstances and risks facing CitiPower in the next regulatory control period.[433] As a result, CitiPower's revised regulatory proposal reinstated the SCADA and network control capex amounts as per its initial regulatory proposal. Therefore, the AER reconsidered the following information previously submitted by CitiPower in support of its initial regulatory proposal:

- initial regulatory proposal – sections 5.8 and 27.2
- CitiPower's responses to AER and Nuttall Consulting requests for information.

At the time of its draft decision, the AER had considered the information provided by CitiPower and had sought to establish that the proposed projects and associated costs were consistent with forecast capital expenditure that reasonably reflects the capex criteria. The AER had requested information evidencing the basis of the forecast SCADA and network control costs given that CitiPower's initial regulatory proposal stated:

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430 ibid., p. 198.
431 ibid., p. 226.
432 CitiPower, *Initial regulatory proposal*, p. 127.
433 CitiPower, *Revised regulatory proposal*, p. 313.

> The forecast expenditure required to install the new [protection and control communications] infrastructure is based on the program costs that CitiPower has incurred in the current regulatory control period.[434] … The forecast expenditure associated with this [Distribution Management System (DMS) field devices] program of works is based on current knowledge of the costs of DMS field devices and the expected volume of devices.[435] …The forecast expenditure associated with this [Increased substation monitoring and automation and security monitory investments] program of works is based on current estimates for the installation of this type of equipment.[436]

Given these statements, the AER assumed the details of the cost estimates supporting the proposed project costs for the forthcoming regulatory control period could be readily sourced by CitiPower and made available to the AER for its consideration. Further, in the draft decision, the AER requested CitiPower to explain how the 'average cost' for SCADA and Network Control projects had been determined and to provide the cost and timing details of the projects in the 2006–2010 regulatory period on which the calculation of 'average cost' is based. In response, CitiPower stated:

> Sections 5, 6 and 7 of the completed SCADA templates provide specific information about the way in which expenditure for each programme and activity has been forecast for the next regulatory control period.
>
> [CitiPower] note[s] that expenditure has generally been forecast in one of the following two ways:
>
> - extrapolating historic expenditure forward for an activity or program. This approach is guided by engineering judgement and knowledge; and
> - multiplying quantities by unit costs.[437]

The AER considered CitiPower's descriptions and explanations in its SCADA templates for the proposed activities/programs and their associated average unit costs were insufficient to establish that the proposed costs are consistent with forecast capital expenditure that reasonably reflects the capex criteria. That is, each of the SCADA and network control material project templates provided as part of the initial regulatory proposal stated that "No benchmarking of expenditure has been undertaken in relation to the cost of this project" and the AER considered CitiPower had not provided any information supporting and justifying the proposed project unit costs.[438]

In assessing CitiPower's revised regulatory proposal, the AER requested CitiPower to provide the contemporary market costs used to determine the unit costs in forecasting the SCADA and network control capex. In response, CitiPower stated it was providing:

> … a series of documents used in project approvals, including quotes and estimates used in the [CitiPower] governance processes, which provide

434 CitiPower, *Initial regulatory proposal*, p. 130.
435 ibid., p. 131.
436 ibid., p. 131.
437 CitiPower, *Response to information requested 4 March 2010*, 12 March 2010.
438 CitiPower, *Initial regulatory proposal*, pp. 409–415; CitiPower, *Response to Nuttall Consulting information request*, 9 March 2010; CitiPower, *Response to Nuttall Consulting information request*, 10 March 2010; CitiPower, *Response to information requested 4 March 2010*, 12 March 2010;.

> evidence of consistency with some key unit rates in the SCADA Program Templates provided to the AER in March 2010.[439]

CitiPower also stated:

> Nuttall Consulting concluded that CitiPower and Powercor Australia are relatively efficient. It therefore follows that unit rates used in the Businesses are efficient.[440]
>
> …the imposition in the Draft Determination of evidentiary threshold requirements, and [CitiPower's] view, contends the AER cannot, at law, seek to establish threshold requirements (such as formal cost benefit analysis, including options analysis, and/or a risk assessment) for the AER to be satisfied that a DNSP's forecast capex reasonably reflects the capex criteria.[441]

The AER has assessed the project cost information provided by CitiPower noting that, although CitiPower's aggregate historical expenditures in certain capex categories may appear to be relatively efficient compared to other DNSPs, this may not be the case for the proposed project cost components for the forthcoming regulatory control period. Further, the AER considers that it is reasonable to expect that at least the projects/programs in the 2006–10 regulatory period would be supported by cost–benefit analysis, particularly where net present values (NPV) are provided in the project documentation provided to the AER – as is the case in the CitiPower and Powercor project justification documentation for the deployment of Powercor's zone substation ethernet network.[442]

The AER has reviewed the additional project cost information provided by CitiPower in August 2010 and considers that it goes some way to supporting the historical/unit costs in CitiPower's SCADA templates even though the project costs are indicative and the actual cost may be +/- 20 per cent of the costs provided.[443]However, the AER notes that the cost information is not directly comparable because the templates describe costs in $2009 terms while the base year for the costs in the indicative project sample provided by CitiPower is not clear.[444]

The AER also notes that CitiPower's Network Protection and Control Communications Strategy 2009–2014 is a high-level document which sets out a need for SCADA and network control communications works during the years 2009–2014. The AER recognises that some of the SCADA templates provided by CitiPower refer to the Network Protection and Control Communications Strategy 2009–2014 as a 'supporting document', however, the AER considers this is not the case for the majority of the proposed projects.[445] Further, the AER considers the Network Protection and Control Communications Strategy 2009–2014 is focussed on updating/modernising CitiPower's communications networks. The AER considers that

439 CitiPower, *Response to information requested 17 August 2010*, 26 August 2010.
440 ibid.
441 ibid.
442 ibid.
443 ibid.
444 CitiPower, *Response to Nuttall Consulting information request*, 9 March 2010; CitiPower, *Response to information requested 17 August 2010*, 26 August 2010.
445 CitiPower, *Response to Nuttall Consulting information request*, 9 March 2010; CitiPower, *Response to Nuttall Consulting information request*, 10 March 2010.

CitiPower has explained and supported its need for strategic development and management of its communications network and to prioritise the installation of proposed new communications infrastructure and the replacement, upgrade, repair and maintenance of its existing communications infrastructure.[446]

Regarding CitiPower's proposed installation of DMS field devices, the AER has not accepted Nuttall Consulting's recommendation not to allow SCADA and network control capex for this project in the forthcoming regulatory control period. The AER notes that Nuttall Consulting based its recommendation on the information submitted by CitiPower with its initial and revised regulatory proposals. However, in response to the AER's separate additional requests for information regarding costs of SCADA and network control projects, CitiPower provided some additional information which the AER considers justifies the proposed project costs and supports inclusion of the DMS field devices project in determining the SCADA and network control allowance in the forthcoming regulatory control period.[447]

Therefore, the AER considers the projects set out at table P.62 relating to CitiPower's communications network are consistent with forecast capital expenditure that reasonably reflects the capex criteria in the forthcoming regulatory control period.

Table P.62 SCADA and network control capex proposed projects—CitiPower

CitiPower function code	Proposed program/project	Proposed capex—direct cost ($'m, 2009)
168 Zone substation automation – SCADA	Zone substation ethernet deployment	1.90
	Implementation of distribution management system (DMS) field devices	3.40
	Installation of IEC 61850 communications	1.20
	New fibre allowance	3.15
	Install ethernet PLC at existing indoor distribution substations	1.05

Note: Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: CitiPower, *Response to Nuttall Consulting information request*, 9 March 2010; CitiPower, *Response to Nuttall Consulting information request*, 10 March 2010.

On the other hand, the AER considers the proposed projects set out at table P.63 are not consistent with forecast capital expenditure that reasonably reflects the capex criteria in the forthcoming regulatory control period. CitiPower has not explained and supported its need for these proposed projects in the SCADA and network control capex category. Although these projects are not discussed in the Network Protection and Control Communications Strategy 2009–2014, the associated proposed step change in expenditure appears to be driven by the anticipated upgrade/improvements of CitiPower's communications networks. That is, the AER considers that the limited

446 CitiPower Pty and Powercor Australia Ltd, *Network Protection and Control Communications Strategy 2009–2014*, 11 November 2009.

447 CitiPower, *Response to information requested 17 August 2010*, 26 August 2010.

information provided by CitiPower did not demonstrate the need for these proposed projects in the forthcoming regulatory control period.[448]

Table P.63 SCADA and network control capex proposed projects—CitiPower

CitiPower function code	Proposed program/project	Proposed capex—direct cost ($'m, 2009)
168 Zone substation automation – SCADA	Allocation for development initiatives	0.75
	Enhanced zone substation monitoring via SCADA	1.75
	Feeder automation	0.90
	Human machine interface (HMI) in zone substations	0.50
	Improved earth fault pre-emptive detection on underground cables	0.75
	Plant condition monitoring solutions	0.95
	Installation of remote monitored fault indicators on the overhead network	0.70
	Transformer monitoring solutions – oil, fans and pumps	0.50
	Upgrade swipe card system	0.30
	Weather stations	0.35
	Zone substation cameras – asset management and security	1.40
	Capacitor bank time/Volt-AMP-Reactive (VAR) control at critical zone substations	0.65
	Cable temperature monitoring	0.25
	Cable oil pressure monitoring	0.25

Note: Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: CitiPower, *Response to Nuttall Consulting information request*, 9 March 2010; CitiPower, *Response to Nuttall Consulting information request*, 10 March 2010.

Table P.64 sets out CitiPower's revised SCADA and network control capex proposal and the AER's final decision.

[448] CitiPower, *Response to Nuttall Consulting information request*, 9 March 2010; CitiPower, *Response to Nuttall Consulting information request*, 10 March 2010.

Table P.64 SCADA and network control capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower revised regulatory proposal	3.8	3.4	3.6	3.6	3.6	18.0
AER final decision	2.0	2.0	2.3	2.3	2.3	10.8

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.5.5.3 Powercor

In its initial regulatory proposal, Powercor stated it had:

> … started updating its existing protection and control communications infrastructure … [and] is also committed to undertaking new investment in the 2011–15 regulatory control period in order to improve its knowledge of network performance, improve data security, increase data visibility and provide more accurate and timely information to customers on fault rectification.[449]

In its revised regulatory proposal, Powercor claimed that "[in] assessing its proposed SCADA and network control capex, the AER did not consider the circumstances and risks facing Powercor Australia in the next regulatory control period.[450] As a result, Powercor's revised regulatory proposal reinstated the SCADA and network control capex amounts as per its initial regulatory proposal. Therefore, the AER reconsidered the following information previously submitted by Powercor in support of its initial regulatory proposal:

- initial regulatory proposal – sections 5.8 and 27.2
- Powercor's responses to AER and Nuttall Consulting requests for information.

At the time of its draft decision, the AER had considered the information provided by Powercor and had sought to establish that the proposed projects and associated costs were consistent with forecast capital expenditure that reasonably reflects the capex criteria. The AER had requested information evidencing the basis of the forecast SCADA and network control costs given that Powercor's initial regulatory proposal stated:

> The forecast expenditure required to install the new [protection and control communications] infrastructure is based on the program costs that Powercor Australia has incurred in the current regulatory control period.[451] … The forecast expenditure associated with this [Distribution Management System (DMS) field devices] program of works is based on current knowledge of the costs of DMS field devices and the expected volume of devices.[452] …The forecast expenditure associated with this [Migration from trunk

[449] Powercor, *Initial regulatory proposal*, p. 122.
[450] Powercor, *Revised regulatory proposal*, p. 301.
[451] Powercor, *Initial regulatory proposal*, p. 125.
[452] ibid., p. 125.

> mobile radio (TMR) to SCADA] program of works is based on actual expenditure in the current regulatory control period.[453] …The forecast expenditure associated with this [Increased substation monitoring and automation and security monitory investments] program of works is based on current estimates for the installation of this type of equipment.[454]

Given these statements, the AER assumed the details of the cost estimates supporting the proposed project costs for the forthcoming regulatory control period could be readily sourced by Powercor and made available to the AER for its consideration. Further, in the draft decision, the AER requested Powercor to explain how the 'average cost' for SCADA and Network Control projects had been determined and to provide the cost and timing details of the projects in the current regulatory period on which the calculation of 'average cost' is based. In response, Powercor stated:

> Sections 5, 6 and 7 of the completed SCADA templates provide specific information about the way in which expenditure for each programme and activity has been forecast for the next regulatory control period.
>
> [Powercor] note[s] that expenditure has generally been forecast in one of the following two ways:
>
> - extrapolating historic expenditure forward for an activity or program. This approach is guided by engineering judgement and knowledge; and
> - multiplying quantities by unit costs.[455]

The AER considered Powercor's descriptions and explanations in its SCADA templates for the proposed activities/programs and their associated average unit costs were insufficient to establish that the proposed costs are consistent with forecast capital expenditure that reasonably reflects the capex criteria. That is, each of the SCADA and network control material project templates provided as part of the initial regulatory proposal stated that "No benchmarking of expenditure has been undertaken in relation to the cost of this project" and the AER considered Powercor had not provided any information supporting and justifying the proposed project unit costs.[456]

In assessing Powercor's revised regulatory proposal, the AER requested Powercor to provide the contemporary market costs used to determine the unit costs in forecasting the SCADA and network control capex. In response, Powercor stated it was providing:

> … a series of documents used in project approvals, including quotes and estimates used in the [Powercor] governance processes, which provide evidence of consistency with some key unit rates in the SCADA Program Templates provided to the AER in March 2010.[457]

Powercor also stated:

[453] ibid., p. 126.
[454] ibid., p. 126.
[455] Powercor, *Response to information requested 4 March 2010*, 12 March 2010.
[456] Powercor, *Initial regulatory proposal*, pp. 416–425; Powercor, *Response to Nuttall Consulting information request*, 9 March 2010; Powercor, *Response to Nuttall Consulting information request*, 10 March 2010; Powercor, *Response to information requested 4 March 2010*, 12 March 2010.
[457] Powercor, *Response to information requested 17 August 2010*, 26 August 2010.

> Nuttall Consulting concluded that CitiPower and Powercor Australia are relatively efficient. It therefore follows that unit rates used in the Businesses are efficient.[458]
>
> …the imposition in the Draft Determination of evidentiary threshold requirements, and in [Powercor's] view, contends the AER cannot, at law, seek to establish threshold requirements (such as formal cost benefit analysis, including options analysis, and/or a risk assessment) for the AER to be satisfied that a DNSP's forecast capex reasonably reflects the capex criteria.[459]

The AER has assessed the project cost information provided by Powercor noting that, although Powercor's aggregate historical expenditures in certain capex categories may appear to be relatively efficient compared to other DNSPs, this may not be the case for the proposed project cost components for the forthcoming regulatory control period. Further, the AER considers that it is reasonable to expect that at least the projects/programs in the 2006–10 regulatory period would be supported by cost–benefit analysis, particularly where net present values (NPV) are provided in the project documentation provided to the AER – as is the case in the CitiPower and Powercor project justification documentation for the deployment of Powercor's zone substation ethernet network.[460]

The AER has reviewed the additional project cost information provided by Powercor in August 2010 and considers that it goes some way to supporting the historical/unit costs in Powercor's SCADA templates even though the project costs are indicative and the actual cost may be +/- 20 per cent of the costs provided.[461]However, the AER notes that the cost information is not directly comparable because the templates describe costs in $2009 terms while the base year for the costs in the indicative project sample provided by Powercor is not clear.[462]

The AER also notes that Powercor's Network Protection and Control Communications Strategy 2009–2014 is a relatively high-level document which sets out a need for SCADA and network control communications works during the years 2009–2014. The AER recognises that some of the SCADA templates provided by Powercor refer to the Network Protection and Control Communications Strategy 2009–2014 as a 'supporting document', however, the AER considers this is not the case for the majority of the proposed projects.[463] Further, the AER considers the Network Protection and Control Communications Strategy 2009–2014 is focussed on updating/modernising Powercor's communications networks. The AER considers that Powercor has explained and supported its need for strategic development and management of its communications network and to prioritise the installation of

[458] ibid.
[459] ibid.
[460] ibid.
[461] ibid.
[462] Powercor, *Response to Nuttall Consulting information request*, 9 March 2010; Powercor, *Response to information requested 17 August 2010*, 26 August 2010.
[463] Powercor, *Response to Nuttall Consulting information request*, 9 March 2010; Powercor, *Response to Nuttall Consulting information request*, 10 March 2010.

proposed new communications infrastructure and the replacement, upgrade, repair and maintenance of its existing communications infrastructure.[464]

Regarding Powercor's proposed installation of DMS field devices, the AER has not accepted Nuttall Consulting's recommendation not to allow SCADA and network control capex for this project in the forthcoming regulatory control period. The AER notes that Nuttall Consulting based its recommendation on the information submitted by Powercor with its initial and revised regulatory proposals. However, in response to the AER's separate additional requests for information regarding costs of SCADA and network control projects, Powercor provided some additional information which the AER considers justifies the proposed project costs and supports inclusion of the DMS field devices project in determining the SCADA and network control allowance in the forthcoming regulatory control period.[465]

Therefore, the AER considers the projects set out at table P.65 relating to Powercor's communications network are consistent with forecast capital expenditure that reasonably reflects the capex criteria in the forthcoming regulatory control period.

Table P.65 SCADA and network control capex proposed projects—Powercor

Powercor function code	**Proposed program/project**	**Proposed capex—direct cost ($'m, 2009)**
168 Zone substation automation – SCADA	Automatic reclosers (ACRs) and SW migration from trunk mobile radio (TMR) View to SCADA	4.60
	Zone substation ethernet deployment	0.90
	Implementation of distribution management system (DMS) field devices	3.40
	Installation of IEC 61850 communications	1.10
	New fibre allowance	2.50
	Regulator (loop) monitoring and control program	1.175
	Rural communications and securing SCADA links to Western and Northern areas of its distribution area	1.18
	Zone substation SCADA communications migration to DNP 3.0	2.15

Note: Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Powercor, *Response to Nuttall Consulting information request*, 9 March 2010; Powercor, *Response to Nuttall Consulting information request*, 10 March 2010.

On the other hand, the AER considers the proposed projects set out at table P.66 are not consistent with forecast capital expenditure that reasonably reflects the capex

[464] CitiPower Pty and Powercor Australia Ltd, *Network Protection and Control Communications Strategy 2009–2014*, 11 November 2009.
[465] Powercor, *Response to information requested 17 August 2010*, 26 August 2010.

criteria in the forthcoming regulatory control period. Powercor has not explained and supported its need for these proposed projects in the SCADA and network control capex category. Although these projects are not discussed in the Network Protection and Control Communications Strategy 2009–2014, the associated proposed step change in expenditure appears to be driven by the anticipated upgrade/improvements of Powercor's communications networks. That is, the AER considers that the limited information provided by Powercor did not demonstrate the need for these proposed projects in the forthcoming regulatory control period.[466]

Table P.66 SCADA and network control capex proposed projects—Powercor

Powercor function code	Proposed program/project	Proposed capex—direct cost ($'m, 2009)
168 Zone substation automation – SCADA	Allocation for development initiatives	0.75
	Communications upgrade to PQM meters	0.25
	Enhanced zone substation monitoring via SCADA	3.50
	Feeder automation	0.70
	Human machine interface (HMI) in zone substations	0.75
	Improved earth fault pre-emptive detection on underground cables	0.45
	Plant condition monitoring solutions	0.95
	Installation of remote monitored fault indicators on the overhead network	1.30
	Transformer monitoring solutions – oil, fans and pumps	1.50
	Upgrade swipe card system	0.60
	Weather stations	0.35
	Zone substation cameras – asset management and security	1.40

Note: Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.

Source: Powercor, *Response to Nuttall Consulting information request*, 9 March 2010; Powercor, *Response to Nuttall Consulting information request*, 10 March 2010.

Table P.67 sets out Powercor's revised SCADA and network control capex proposal and the AER's final decision.

[466] Powercor, *Response to Nuttall Consulting information request*, 9 March 2010; Powercor, *Response to Nuttall Consulting information request*, 10 March 2010.

Table P.67 SCADA and network control capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor revised regulatory proposal	5.8	6.2	6.3	6.1	6.0	30.3
AER final decision	3.7	3.4	3.7	3.3	3.2	17.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.5.5.4 JEN

JEN stated that the AER had accepted its proposed forecast capex for SCADA and network control.[467]

Table P.68 lists JEN's proposed programs/projects in the SCADA and network control capex category.

Table P.68 SCADA and network control capex proposed projects—JEN

Proposed program/project	Description
Zone substation integrated security system	Integration of the various zone substation security measures in an electronic security system

Source: JEN, *JEN Response to Nuttall Consulting Information Requests dated 18 Jan 2010 – Item 10*, 10 February 2010.

Table P.69 sets out JEN's revised SCADA and network control capex proposal and the AER's final decision.

Table P.69 SCADA and network control capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN revised regulatory proposal	0.6	0.8	1.0	0.3	0.0	2.8
AER final decision	0.6	0.8	1.0	0.3	0.0	2.8

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: JEN, *Revised regulatory proposal*, RIN template 2.1, July 2010.

P.5.5.5 SP AusNet

As SP AusNet's revised regulatory proposal reinstated the SCADA and network control capex amounts as per its initial regulatory proposal, the AER reconsidered the following information previously submitted by SP AusNet in support of its initial regulatory proposal:

467 JEN, *Revised regulatory proposal*, p. 168.

- initial regulatory proposal – section 6.11 and IT Strategy (appendix F to initial regulatory proposal)
- SP AusNet responses to AER and Nuttall Consulting requests for information.

The AER also requested further information evidencing the basis of the forecast SCADA master station IT costs and SP AusNet's progress relative to its proposed implementation program as set out at figure 17 of SP AusNet's IT Strategy.[468] In response, SP AusNet stated:

> The most up-to-date/current SCADA and network control projects implementation timetable covering the 2011–2015 period is as per the Revised Proposal provided to the AER on 20 July 2010 and SP AusNet's submitted IT Strategy.[469]

The AER did not find a discussion of the SCADA and network control implementation program in SP AusNet's revised regulatory proposal and therefore has considered only the information at figure 17 of SP AusNet's IT Strategy. SP AusNet did not provide a copy of the specific business case relating to SCADA Master Station IT as described in its IT Strategy:

> At the date of this document, SP AusNet is preparing a detailed business case for the 2010 forecast project to upgrade SCADA Master Station IT. This business case is not sufficiently advanced to use as a basis for estimation, and a competitive tender process is still to be conducted.[470]

Instead, SP AusNet's response included business case documentation for the Network Management Automation (NMA) IT program which includes upgrade of the Areva software for SCADA/EMS IT systems would largely be completed in the 2006–2010 regulatory period.[471]

The AER did not consider that proposed capex relating to the Distribution Outage Management System (DOMS) should be included in SCADA and network control capex in the forthcoming regulatory control period because the DOMS system is a separate IT system to the Areva SCADA/EMS system and, although it places design requirements on the SCADA Master System IT upgrade project, it is not 'SCADA Master System IT'.[472] Further, the AER considers the forecast expenditures described in SP AusNet's business case documentation titled "Network Management Automation IT Program – Variation" is largely unrelated to the SCADA and network control capex given the program's target completion date is November 2011. That is, figure 17 (at page 59 of SP AusNet's IT Strategy) indicates that a "SCADA Upgrade" project will be undertaken during calendar years 2014 and 2015 which is consistent with SP AusNet's statements suggesting that the supported life of SCADA Master Station IT systems is consistent with other IT systems.[473] Therefore, given the current

468 SP AusNet, *Information Technology Strategy (CY2011 – 2015)*, Electricity Distribution Network, Issue 9, November 2009, p. 59.
469 SP AusNet, *Response to information requested 17 August 2010*, 23 August 2010.
470 SP AusNet, *Information Technology Strategy (CY2011 – 2015)*, Electricity Distribution Network, Issue 9, November 2009, p. 60.
471 SP AusNet, R*esponse to information requested 17 August 2010*, 23 August 2010.
472 ibid.
473 SP AusNet, *Initial regulatory proposal*, p.151.

SCADA Master Station IT was commissioned in 2007 and is being upgraded in 2010, the AER expects it is likely the SCADA Master Station IT systems will no longer be supported in 2014 and will require to be upgraded at that time.[474]

Therefore, having considered the information submitted by SP AusNet, and given that SP AusNet has stated that its proposed SCADA and network control capex relates only to SCADA Master Station IT, the AER considers that the forecast costs described as "SCADA Minor Enhancements" and "SCADA Upgrade" are the only relevant costs which should be included in the SCADA and network control capex category in the forthcoming regulatory control period.

The AER considers that its final decision on SP AusNet's SCADA and network control capex is consistent with SP AusNet's historical expenditure on upgrade of its SCADA Master Station IT. That is, SP AusNet has advised the AER that it completed an upgrade of its SCADA Master Station IT for its transmission network in 2001 and its statement that "the actual cost of the 2001 SCADA Master Station IT Upgrade was $3,816,715 (nominal)" is consistent with statements in its IT Strategy indicating this historical cost was approximately $4 million ($nominal).[475]

The AER has based its final decision on SP AusNet's SCADA and network control capex on SP AusNet's forecast expenditures for "SCADA Minor Enhancements" and "SCADA Upgrade" projects as set out at table 18 of its IT Strategy.[476] The AER notes SP AusNet's statement that these amounts include "[a] contingency factor of 20% …consistent with the residual risk …and recognises that competitive tender processes are to be conducted".[477]

Table P.70 sets out SP AusNet's revised SCADA and network control capex proposal and the AER's final decision.

Table P.70 SCADA and network control capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet revised regulatory proposal	0.6	0.7	1.1	4.1	0.9	7.4
AER final decision	1.0	1.0	1.0	1.0	1.0	4.8

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.
Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010.

474 ibid., p.151.
475 SP AusNet, *Response to information requested 17Ausgust 2010*, 23 August 2010; SP AusNet, *Information Technology Strategy (CY2011 – 2015)*, Electricity Distribution Network, Issue 9, November 2009, p. 61.
476 SP AusNet, *Information Technology Strategy (CY2011 – 2015)*, Electricity Distribution Network, Issue 9, November 2009, p. 61.
477 ibid., pp. 60–61.

P.5.5.6 United Energy

United Energy stated that its SCADA and network control capex proposal consisted of two separate components:[478]

- Control Room relocation
- increasing data centre fibre capacity.

It requested the AER consider both these projects in coming to its final decision. Therefore, the AER reconsidered the following information submitted by United Energy in support of its initial regulatory proposal:

- initial regulatory proposal (section 6.9) including capex model (appendix B5 to the initial regulatory) proposal
- revised regulatory proposal (section 6.9) including capex model (appendix B4 to the revised regulatory proposal)
- information submitted in response to AER and Nuttall Consulting requests for information.

The AER's draft decision considered that United Energy had not demonstrated that a new business structure necessitating the in-sourcing of control room functions would be in place in the forthcoming regulatory control period. United Energy has since confirmed that tenders seeking to provide services under the transformed business model had not offered to provide control room services.[479] Consistent with United Energy's transformed business model, the control room services will no longer be provided by Jemena Asset Management (JAM) and United Energy has taken steps to 'in-source' the provision of the control room services. On this basis, the AER has accepted United Energy's proposed capex in relation to the proposed expenditures relating to fit-out of new control room facilities in the forthcoming regulatory control period. The AER accepts United Energy's proposed control room relocation project costs are conservative because they have been based on a $2005 estimate and that the proposed project costs are direct costs.[480] As United Energy has not sought to revise its proposed project costs, the AER considers the proposed amount of $3.204 million ($2010) for the proposed project is consistent with forecast capital expenditure that reasonably reflects the capex criteria.

In the case of the proposed project to increase United Energy's data centre fibre capacity, the AER notes that United Energy's Asset Strategy Strategic Planning Paper for the project indicates the project budget cost is $500,000 whereas United Energy has proposed a total of $1.477 million ($2010) in its revised regulatory proposal.[481] United Energy confirmed the proposed project costs were direct costs and explained the cost difference between these amounts was due to the AER having been provided

478 United Energy, *Revised regulatory proposal*, p. 145.
479 United Energy, *Revised regulatory proposal*, p. 145.
480 United Energy, *Response to Nuttall Consulting information request*, 23 February 2010; United Energy, *Response to information requested 7 September 2010*, 15 September 2010.
481 United Energy, *Asset Strategy Strategic Planning Paper: Increasing Data Centre Fibre Capacity*, Undated, pp. 7, 9–11; United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.

with the incorrect version of the relevant asset management plan.[482] Having considered United Energy's updated asset management plan, the AER has not accepted United Energy's proposed project costs because the document identifies:

- Option 1 (16 channel passive Coarse Wavelength Division Multiplexing (CWDM) or Dense Wavelength Division Multiplexing (DWDM) system) is the most economic option, apart from the 'do nothing' option[483]

- A passive DWDM system with redundant fibre routes can be implemented under Option 1[484]

- Option 2 (DWDM active system) allows for future expandability which can be utilised as the electricity network evolves into a smart network in the future.[485]

That is, on the basis of the information submitted by United Energy, the AER considers that implementation of Option 1 (16 channel passive DWDM system) is the most prudent and efficient option and that, should United Energy implement Option 2 (active DWDM system), it should pay the additional costs because it would be making the investment in anticipation of future benefits related to smart network developments.

Accordingly, the AER has not accepted United Energy's proposed amount of $1.5 million ($2010) for this project and substituted an amount of $500,000 ($2010) based on implementation of Option 1 (16 channel passive DWDM system) as described in United Energy's Asset Strategy Strategic Planning Paper: Increasing Data Centre Fibre Capacity document.[486]

Table P.71 sets out United Energy's revised SCADA and network control capex proposal and the AER's final decision.

Table P.71 SCADA and network control capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy revised regulatory proposal	0.0	0.7	0.7	0.0	0.0	1.5
AER final decision	0.0	0.5	3.2	0.0	0.0	3.7

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.
Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.

[482] United Energy, *Response to information requested 7 September 2010*, 15 September 2010; United Energy, *Response to information requested 20 September 2010*, 24 September 2010.
[483] United Energy, *Asset Strategy Strategic Planning Paper: Increasing Data Centre Fibre Capacity*, Version 1.1, Undated, p. 12.
[484] ibid., p. 7.
[485] ibid., p. 9.
[486] ibid., p. 7, 11–12.

P.5.6 AER conclusion

This section P.5 has assessed the direct costs of the proposed allowance for SCADA and network control capex which is one component of each Victorian DNSP's proposed total forecast capital expenditure. The AER considers that the direct costs determined in this section P.5 are consistent with the requirement in clause 6.5.7(c) of the NER that the forecast capital expenditure reasonably reflects the capital expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capital expenditure.

That constituent decision, which should be read together with this appendix, is discussed at chapter 8.

Table P.72 sets out the AER's conclusion on the direct cost of each Victorian DNSP's revised regulatory proposals on SCADA and network control capex which it considers is consistent with forecast capital expenditure that reasonably reflects the capex criteria.

As explained at the beginning of this section P.5, in coming to this view, the AER has assessed the information submitted in support of each Victorian DNSP's revised regulatory proposals on SCADA and network control capex, having regard to the capex factors. Where relevant, the AER has made the minimum necessary change to the Victorian DNSPs' forecast SCADA and network control capex.

Table P.72 AER conclusion— Victorian DNSPs' 2011–15 SCADA and network control capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	2.0	2.0	2.3	2.3	2.3	10.8
Powercor	3.7	3.4	3.7	3.3	3.2	17.2
JEN	0.6	0.8	1.0	0.3	0.0	2.8
SP AusNet	1.0	1.0	1.0	1.0	1.0	4.8
United Energy	0.0	0.5	3.2	0.0	0.0	3.7

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes margins, overheads and real cost increases.

P.6 Non-network IT

This section considers the Victorian DNSPs' proposals on the non-network IT capex category.

As noted at the beginning of the capex chapter (chapter 8) of this final decision, each Victorian DNSP proposed allowances for non-network IT capex as a component of its total proposed forecast capital expenditure for the 2011–15 regulatory control period. The assessment of this component is relevant to determining whether the AER is satisfied that the total proposed forecast capital expenditure or its estimate of the required capital expenditure reasonably reflects the capital expenditure criteria.

Specifically, this section assesses the proposed allowances and what the level of efficient direct cost expenditure for non-network IT capex which a prudent operator, in the circumstances of each Victorian DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capital expenditure objectives.

Therefore, this section gives the reasons for the AER's final decision in respect of the direct costs relating to the Victorian DNSPs' respective revised regulatory proposals on non-network IT capex.

That is, in accordance with NER cl.6.12.2, this section sets out the basis and rationale for the AER's final decision including:[487]

- details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the AER
- the values adopted by the AER for the input variable in any calculations and formulae, including:
  - whether those values have been taken or derived from the Victorian DNSP's initial or revised regulatory proposals, and
  - if not, the rationale for the adoption of those values
- details of any assumptions made by the AER in undertaking any material and quantitative analyses
- reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretions, as referred to in chapter 6 of the NER, for the purposes of the AER's final decision.

Approach

Where a Victorian DNSP accepted the AER's draft decision on the direct costs for the non-network IT capex, the AER has approved that same direct cost amount(s) in its final decision.

Where a Victorian DNSP did not accept the AER's draft decision on the non-network IT capex direct costs, the AER has considered whether the revised regulatory proposal in respect of that proposed capex reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant Victorian DNSP would require to meet the capex objectives.

That is, having regard to the capex factors set out at NER cl.6.5.7(e), and particularly:

- the information included in or accompanying the building block proposal

[487] NER, clause 6.12.2.

- submissions received in the course of consulting on the building block proposal
- analysis undertaken by or for the AER and published before the distribution determination is made in its final form
- benchmark capital expenditure that would be incurred by an efficient distribution DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods

the AER has considered whether the proposed projects are in accordance with good industry practice including whether:

- there is a justifiable need for the proposed capex
- the proposed projects have been objectively and competently analysed to a standard that is consistent with good industry practice
- the proposed projects align with strategic capex plans and policies.

The AER sought explanation of the drivers of any proposed step changes in the non-network IT capex. The historical underlying trend in expenditure in the non-network IT capex was used as the starting point to assess whether a step change (increase or decrease) in expenditure had been proposed. However, given that the historical trend cannot completely determine future requirements, the AER requested the Victorian DNSPs to provide relevant economic analysis which clearly demonstrated the need to undertake the proposed projects in the forthcoming regulatory control period. The AER expected the analysis would demonstrate how engineering judgements had been translated into step changes in expenditure and be supported by cost-benefit analysis including options analysis. Having said that, the AER also expected the analysis would be appropriate in respect of the materiality of the proposed project expenditures as a proportion of the total capex for non-network IT.

The AER must allow each Victorian DNSP adequate funding to recover at least its respective efficient costs of providing direct control services. The AER is also aware that each Victorian DNSP must also satisfy safety and other regulatory and legislative obligations while managing its respective networks in accordance with good electricity practices. Therefore, in assessing each Victorian DNSP's proposed expenditures in non-network IT capex, the AER considered:

- whether the proposed projects aligned with strategic capex plans and policies
- changes in timing have been considered to ensure prudent decision-making
- processes or systems for project approval reflected good governance and business practices for undertaking capital projects
- cost-estimating processes incorporate feed-back from specific experience.

Where the AER has not accepted a Victorian DNSP's revised regulatory proposal, in respect of the direct costs of projects proposed in non-network IT, the AER has made the minimum necessary change to the Victorian DNSP's forecast capex direct cost expenditure.

The AER's assessment and final decision on a realistic expectation of the demand forecast and costs inputs required to achieve the capex objectives are set out at chapter 5 and appendix K respectively of this final decision. The AER's final decision on the total capex reasonably required by each Victorian DNSP is set out at chapter 8 and includes amounts for the direct costs (as set out in this appendix) for non-network IT capex, as adjusted for overheads, real cost increases and margins.

P.6.1 AER draft decision

The Victorian DNSPs indicated IT investments typically have a 5 to 7 year life and require renewal thereafter. As a result, they considered they faced risks from deferred/delayed IT investments. They submitted project plans for the forthcoming regulatory control period and explained that the timing of their replacement/upgrade of IT applications software had been affected by the mandated Advanced Metering Infrastructure (AMI) roll-out. The AER considered that the business and operational challenges and risks faced by the Victorian DNSPs had not changed between the 2006–10 regulatory period and the forthcoming regulatory control period.

The AER considered that the Victorian DNSPs do not have 'agile' IT architecture supporting business operation and service delivery. The AER accepted Nuttall Consulting's assessment that the absence of agile IT environments would hinder the Victorian DNSPs' ability to complete the proposed IT projects in the forthcoming regulatory control period. The AER also considered it likely that the Victorian DNSPs would defer projects or adopt alternative projects in the forthcoming regulatory control period.

Therefore, the AER did not accept the Victorian DNSPs' proposed capex amounts and substituted amounts based on amounts recommended by Nuttall Consulting for non-network IT capex.

P.6.1.1 CitiPower

Table P.73 sets out CitiPower's initial proposed non-network IT capex and the AER's draft decision.

Table P.73 Non-network IT capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower initial regulatory proposal	8.6	7.6	8.3	11.4	9.0	44.9
AER draft decision	5.0	4.9	4.9	4.7	4.7	24.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 415, 424.

P.6.1.2 Powercor

Table P.74 sets out Powercor's initial proposed non-network IT capex and the AER's draft decision.

Table P.74 Non-network IT capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor initial regulatory proposal	22.5	19.0	18.7	25.0	19.7	104.7
AER draft decision	12.2	12.1	12.0	11.4	11.4	59.1

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 415, 424.

P.6.1.3 JEN

Table P.75 sets out JEN's initial proposed non-network IT capex and the AER's draft decision.

Table P.75 Non-network IT capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN initial regulatory proposal	16.9	17.4	13.9	5.2	5.3	58.8
AER draft decision	9.8	9.6	9.5	9.3	9.1	47.3

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 415, 424.

P.6.1.4 SP AusNet

Table P.76 sets out SP AusNet's initial proposed non-network IT capex and the AER's draft decision.

Table P.76 Non-network IT capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet initial regulatory proposal	31.9	37.1	27.1	30.2	16.7	143.0
AER draft decision	14.8	14.6	14.4	14.2	14.0	72.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Sp AusNet's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 415, 424.

P.6.1.5 United Energy

Table P.77 sets out United Energy's initial proposed non-network IT capex and the AER's draft decision.

Table P.77 Non-network IT capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy initial regulatory proposal	29.2	28.3	18.1	15.9	7.1	98.5
AER draft decision [a]	15.1	15.1	15.1	15.1	15.1	75.6

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.
(a) Table 8.53 of the AER's draft decision incorrectly stated an annual amount of $19.7 million ($, 2010)
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 415, 424.

P.6.2 Victorian DNSP revised regulatory proposals

P.6.2.1 CitiPower

CitiPower considered the AER should include 2009 actual data in forecasting the non-network IT capex in the forthcoming regulatory control period by reference to historical expenditure.[488]

CitiPower stated its expenditure in the 2006–10 regulatory period had been reduced relative to the ESCV's allowance because of the mandated AMI roll-out.[489] It stated that it had deferred the replacement of its Customer Information System (CIS) because of the potential for increased risks in relation to the delivery of its AMI project.[490] CitiPower noted that its proposed replacement of its CIS system was a joint project between CitiPower, Powercor and ETSA Utilities. CitiPower considered the AER's draft decision in relation to its own non-network IT capex was inconsistent with the AER's provision of an allowance for capex for ETSA Utilities' CIS replacement project.[491] CitiPower stated there is no vendor support for its CIS and that failure to update the system will mean the full benefits of AMI cannot be realised.[492]

In relation to its proposed AMI leveraged projects, CitiPower considered the AER had discounted the evidentiary value of the associated PricewaterhouseCoopers (PwC) report to CitiPower.[493] In particular, CitiPower considered that the PwC report was an independent and expert opinion and, as such, the probative value of the report was increased.[494] In CitiPower's view, the AER had concluded that the probative value of

488 CitiPower, *Revised regulatory proposal*, p. 321.
489 ibid., p. 320.
490 ibid., p. 325.
491 ibid., p. 325.
492 ibid., pp. 325–326.
493 ibid., p. 328.
494 ibid., p. 328.

the PwC report was reduced because it did not contain CitiPower's internal assessment.[495] In response to the AER's draft decision, CitiPower removed one of the proposed AMI leveraged projects which may generate an STPIS saving. However, it stated the AER had incorrectly assumed that any deferment of network reinforcement projects resulting from enhanced load shedding capabilities would be realised in the forthcoming regulatory control period.[496] That is, CitiPower considered that any reinforcement capex savings would only be realised after completion of the AMI leveraged projects in 2015 and therefore, if the AER did not allow network reinforcement projects in the 2016–20 regulatory control period, the benefits of the network deferral would be passed directly to customers without CitiPower obtaining any benefit.[497]

CitiPower considered that much of its proposed capex aims to keep its systems 'agile and avoid technical and commercial obsolescence. It did not consider that a capex allowance based on its historical non-network IT capex expenditure will be sufficient to allow it to meet the capex objectives in the forthcoming regulatory control period. CitiPower requested the AER "actively engage in considering the material" in both its initial and revised regulatory proposals and considered that, in doing so, the AER would be satisfied the proposed expenditure was prudent and efficient and reasonably reflects the capex criteria.[498]

Table P.78 sets out the AER's draft decision and CitiPower's revised non-network IT capex proposal.

Table P.78 Non-network IT capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	5.0	4.9	4.9	4.7	4.7	24.2
CitiPower revised regulatory proposal	8.4	7.5	7.4	11.2	8.9	43.4

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 424.

P.6.2.2 Powercor

Powercor considered the AER should include 2009 actual data in forecasting the non-network IT capex required in the forthcoming regulatory control period by reference to historical expenditure.[499]

Powercor stated its expenditure in the 2006–10 regulatory period had been reduced relative to the ESCV's allowance because of the mandated AMI roll-out.[500] It stated

495 ibid., p. 328.
496 ibid., pp. 328–329.
497 ibid., pp. 329–330.
498 ibid., p. 327.
499 Powercor, *Revised regulatory proposal*, p. 311.
500 ibid., p. 311.

that it had deferred the replacement of its Customer Information System (CIS) because of the potential for increased risks in relation to the delivery of its AMI project.[501] Powercor noted that its proposed replacement of its CIS system was a joint project between CitiPower, Powercor and ETSA Utilities. Powercor considered the AER's draft decision in relation to its own non-network IT capex was inconsistent with the AER's provision of an allowance for capex for ETSA Utilities' CIS replacement project.[502] Powercor stated there is no vendor support for its CIS and that failure to update the system will mean the full benefits of AMI cannot be realised.[503]

In relation to its proposed AMI leveraged projects, Powercor considered the AER had discounted the evidentiary value of the associated PricewaterhouseCoopers (PwC) report to Powercor.[504] In particular, Powercor considered that the PwC report was an independent and expert opinion and, as such, the probative value of the report was increased.[505] In Powercor's view, the AER had concluded that the probative value of the PwC report was reduced because it did not contain Powercor's internal assessment.[506] In response to the AER's draft decision, Powercor removed one of the proposed AMI leveraged projects which may generate an STPIS saving. However, it stated the AER had incorrectly assumed that any deferment of network reinforcement projects resulting from enhanced load shedding capabilities would be realised in the forthcoming regulatory control period.[507] That is, Powercor considered that any reinforcement capex savings would only be realised after completion of the AMI leveraged projects in 2015 and therefore, if the AER did not allow network reinforcement projects in the 2016–20 regulatory control period, the benefits of the network deferral would be passed directly to customers without Powercor obtaining any benefit.[508]

Powercor considered that much of its proposed capex aims to keep its systems 'agile and avoid technical and commercial obsolescence. It did not consider that a capex allowance based on its historical non-network IT capex expenditure will be sufficient to allow it to meet the capex objectives in the forthcoming regulatory control period. Powercor requested the AER "actively engage in considering the material" in both its initial and revised regulatory proposals and considered that, in doing so, the AER would be satisfied the proposed expenditure was prudent and efficient and reasonably reflects the capex criteria.[509]

Table P.79 sets out the AER's draft decision and Powercor's revised non-network IT capex proposal.

501 ibid., p. 315.
502 ibid., p. 315.
503 ibid., p. 316.
504 ibid., p. 318.
505 ibid., p. 318.
506 ibid., p. 318.
507 ibid., pp. 318–319.
508 ibid., p. 320.
509 ibid., p. 318.

Table P.79 Non-network IT capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	12.2	12.1	12.0	11.4	11.4	59.1
Powercor revised regulatory proposal	22.4	19.2	17.5	26.3	20.1	106.4

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.

Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 424.

P.6.2.3 JEN

JEN stated that neither the AER nor Nuttall Consulting had raised issues with the prudency or efficiency of its proposed non-network IT capex program.[510] It considered the AER's substitute non-network IT capex relied on Nuttall Consulting's conclusion that JEN's IT architecture was not sufficiently agile.

JEN stated it has undertaken an extensive IT modernisation program and has progressively improved the agility of its IT infrastructure by investing well above its non-network IT allowance.[511] It also noted that the IT architectures and technologies it has implemented were mainstream and typical for the Australian energy at the time they were implemented. Further, the IT infrastructure was implemented as 'value-for-money' based on competitive tender and the use of contemporary technologies.[512]

JEN noted that it has undertaken IT capability initiatives which has meant that new programs have been delivered that were not envisaged at the time of its 2006–10 regulatory proposal and the ESCV's final determination.[513] It explained that any deferral of expenditure during the 2006–10 regulatory period was due to vendor product replacement and external events such as ownership changes, and not due to its capability or IT architecture.[514]

Table P.80 sets out the AER's draft decision and JEN's revised non-network IT capex proposal.

[510] JEN, *Revised regulatory proposal*, Appendix 8.9, p. 6.
[511] ibid., pp. 169–170.
[512] ibid., p. 171.
[513] ibid., Appendix 8.9, p. 6.
[514] ibid., pp. 169–170.

Table P.80 Non-network IT capex–direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	9.8	9.6	9.5	9.3	9.1	47.3
JEN revised regulatory proposal	17.2	17.6	14.1	5.3	5.4	59.6

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.

Source: JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 424.

P.6.2.4 SP AusNet

In SP AusNet's view, the AER's draft decision is inconsistent with clause 6.5.7(c)(2) of the NER which provides that a DNSP should be able to recover the costs that a prudent operator in its circumstances would require to achieve the capex objectives. SP AusNet stated it did not support the AER's forecasting approach for non-network IT capex.[515] SP AusNet observed it has exceeded the allowance provided by the ESCV and has funded the difference at a cost to its shareholders. It explained that it is difficult to accurately forecast IT capex requirements because of changing technology and uncertain events, factors and considerations.[516] SP AusNet considered that an allowance which reflected historic capex would likely produce an allowance that systematically understated the requirements of the business.

SP AusNet stated the AER had erroneously decided that historical expenditure would effectively cover SP AusNet's non-network IT needs.[517] SP AusNet engaged Deloitte to provide advice on the AER's approach to its draft decision and specific recommendations in Nuttall Consulting's report to the AER. SP AusNet stated the Deloitte report was critical of the approach described in Nuttall Consulting's report.[518] SP AusNet referenced Deloitte's report and stated that the AER's draft decision provided a lower allowance on a per customer basis than the AER had recently approved for NSW and South Australian electricity distribution businesses.[519]

SP AusNet's criticisms of the AER's draft decision also included:

- the AER's draft decision lacked rigour and showed a failure to consider SP AusNet's "industry expert-validated and clearly costed" IT strategy and engage in the detail of the proposed programs[520]
- the AER applied a different method in determining SP AusNet's non-network IT capex compared to the other Victorian DNSPs. SP AusNet did not consider the AER addressed this issue when requested to provide reasons for its decision.[521] Therefore, in this case, SP AusNet considered the AER's decision to exercise its

515 SP AusNet, *Revised regulatory proposal*, p. 143.
516 ibid., p. 143.
517 ibid., p. 142.
518 ibid., p. 142.
519 ibid., p. 144.
520 ibid., p. 150.
521 ibid., p. 145.

discretion in distinguishing between the Victorian DNSPs amounted to an unreasonable and an unjustifiable bias in the outcome.[522] SP AusNet stated this element of the AER's decision also represented a failure to adhere to basic decision-making principles of procedural fairness.[523]

- the AER's decision needs to 'factor in' SP AusNet's IT ownership model, however, there is no basis for the AER to seek to micro-manage SP AusNet's commercial decisions[524]
- Nuttall Consulting's assessment of SP AusNet's IT Strategy did not examine the relationship between applications and infrastructure. Nuttall Consulting's review of SP AusNet's non-network IT proposal was not comprehensive and should not be heavily relied upon by the AER to determine SP AusNet's non-network IT capex in the forthcoming regulatory control period[525]
- the AER adopted Nuttall Consulting's definition of IT agility and the AER's view that SP AusNet has not sought to address agility was incorrect.[526] In contrast, SP AusNet noted that Deloitte's report to SP AusNet confirmed that its infrastructure was typical of many organisations in the utilities industry that have embraced virtualisation and are providing agility capabilities in their IT environments[527]
- cloud service technology is not suitable to a utilities business. SP AusNet referenced Deloitte's report in stating that utility software environments require 'heavy customisation' to meet business requirements[528]
- SP AusNet's 2009–10 non-network IT actual capex reflects decisions to derive synergies between IT systems and infrastructure required to support AMI obligations and those required for standard control services[529]
- the AER's draft decision conflicts with the ESCV's implicit assumption that upgraded customer communications will occur in the forthcoming regulatory control period[530]
- the AER should include 2009 data in historical expenditure analysis because audited 2009 regulatory accounts are now available.[531] Further, the AER's historical trend analysis is incorrect and not an adequate basis for deciding SP AusNet's non-network IT capex for the forthcoming regulatory control period because it did not consider the 2009 data[532]

522 ibid., p. 146.
523 ibid., p. 146.
524 ibid., p. 150.
525 ibid., pp. 146–147.
526 ibid., p. 147.
527 ibid., p. 147.
528 ibid., p. 150.
529 ibid., p. 145.
530 ibid., p. 151.
531 ibid., p. 144.
532 ibid., p. 145.

- SP AusNet also expressed concern that it would be penalised if it overspent its non-network IT capex allowance. That is, its RAB for the 2016–20 regulatory control period will be reduced by an amount equal to the actual (and not forecast) depreciation. Therefore, it proposed that the capex efficiency regime to be applied to its non-network IT capex exclude a return of capital component and retain only the return on capital component.[533]

Table P.81 sets out the AER's draft decision and SP AusNet's revised non-network IT capex proposal.

Table P.81 Non-network IT capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	14.8	14.6	14.4	14.2	14.0	72.0
SP AusNet revised regulatory proposal	31.9	37.1	27.1	30.2	16.7	143.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Sp AusNet's proposed margins, overheads and real cost increases.

Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15,* Draft decision, June 2010, p. 424.

P.6.2.5 United Energy

United Energy noted the words in the AER's draft decision did not match the models provided, so it interpreted the AER's draft decision as recommending a non-network IT allowance of $15.1 million($2010, direct cost—excluding margins, overheads and real cost escalators) per year in the forthcoming regulatory control period.

United Energy provided updated costs relating to its proposed ERP–SAP Consolidation project after reassessing its ability to implement its IT Strategy, the accuracy of its cost estimates and the mix of capex and opex and its ability to deliver its total proposed IT program.[534] It also noted that its Board and management had certified the deliverability component of the RIN submitted as part of its initial regulatory proposal to the AER.

United Energy stated the AER could not dismiss the proposed IT program on the basis that Nuttall Consulting believed the possibility that 40 per cent of the proposed program can be deferred.[535] It also considered the AER had failed to recognise projects in the final two years of the forthcoming regulatory control period which United Energy considered were required to achieve forecast opex efficiencies in the same period.

United Energy believed that both Nuttall Consulting and the AER had failed to understand its IT strategy. That is, the Nuttall Consulting report and the AER's draft

533 ibid., pp. 151–152.
534 United Energy, *Revised regulatory proposal*, pp. 146–147.
535 ibid., p. 147.

decision were incorrect and did not accurately portray information provided by United Energy.[536]

United Energy also noted that it participates in the Australian Energy Market Operator (AEMO) Energy Market Information Technology Reference Group and is currently chairing the group. As such, it stated it was not aware of any trends or obligations-based drivers to move towards a flexible/agile architecture based on 'cloud computing' or 'Infrastructure as a Service' services in the Australian electricity market.[537] Further, United Energy stated it was not aware of any other market participants who utilise 'cloud computing' or 'Infrastructure as a Service' services to provide critical IT systems.[538]

United Energy considered it was unrealistic for the AER to expect United Energy to anticipate and therefore cost the implementation of new applications for requirements (such as those relating to AMI) that were undefined before the completion of the ESCV's EDPR 2006–10.

Table P.82 sets out the AER's draft decision and United Energy's revised non-network IT capex proposal.

Table P.82 Non-network IT capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision [a]	15.1	15.1	15.1	15.1	15.1	75.6
United Energy revised regulatory proposal	23.5	36.5	27.6	16.0	7.2	111.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.

(a) Table 8.53 of the AER's draft decision incorrectly stated an annual amount of $19.7 million ($, 2010)

Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 424.

P.6.3 Submissions

The AER received a submission from the Energy Users Coalition of Victoria (EUCV) on the non-network IT capex proposed by the Victorian DNSPs.

The EUCV supported the AER's approach and considered it was "detailed, robust and reflect[ed] the actuality of what the [Victorian DNSPs] themselves considered to be appropriate investment in these areas".[539]

[536] ibid., p. 150.
[537] ibid., p. 152.
[538] ibid., p. 152.
[539] Energy Users Coalition of Victoria, *Australian Energy Regulator Victorian Electricity Distribution Revenue Reset AER Draft Decisions and Revised Regulatory Proposals on CitiPower, Jemena,*

P.6.4 Consultant review

In the case of non-network IT capex, Nuttall Consulting assessed matters raised in the revised regulatory proposals submitted by each Victorian DNSP.

Nuttall Consulting considered the following issues were relevant to its review of the Victorian DNSPs' proposals on non-network IT in the forthcoming regulatory control period.

- Data centre consolidation—the Victorian DNSPs have increased their data centre space at a time when, in general, organisations have been consolidating data centres to reduce IT costs.[540] The Victorian DNSPs have indicated the AMI implementation required a separate IT environment and therefore increased data centre requirements which they intend to reassess during consolidation of their IT production systems at some future date.[541]

- IT agility—rapid technological advancement and a changing commercial and regulatory environment requires business IT systems to be flexible or 'agile'.[542] As a result, the Victorian DNSPs consider complex options for delivering new applications, upgrading or decommissioning existing applications and management of the supporting IT infrastructure.[543]

- IT infrastructure agility—rapid and cost-effective adaptation to business change requires rapid deployment in IT compute, storage and connectivity (networking) areas.[544] A first step towards IT infrastructure agility is the adoption of 'virtualisation' and although each Victorian DNSP has adopted some virtualisation functionality, the level of adoption is minimal to low.[545] Modern virtualisation products are capable of virtualising CPU and database-intensive applications and support concerns can be addressed through negotiation with software vendors.[546]

- Capacity planning—although it is not reasonable to expect the Victorian DNSPs to rent compute and storage resources, such capability is currently available via Google and Amazon.[547]

- Historical underspend—the Victorian DNSPs did not provide evidence that historical underspend was not prudent or had resulted in adverse consequences.[548] Given the Victorian DNSPs' planning processes have not sufficiently allowed for

Powercor, SP AusNet and United Energy Applications: A response by Energy Users Coalition of Victoria, August 2010, p. 22.

540 Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 40–41.

541 ibid., p. 41.

542 ibid., p. 41.

543 ibid., p. 41.

544 ibid., p. 41.

545 ibid., pp. 43–45.

546 ibid., p. 44.

547 ibid., p. 45.

548 ibid., pp. 45–47.

project delays, the capex requirement in the forthcoming regulatory control period should be lower than proposed.[549]

Nuttall Consulting considered that the Victorian DNSPs provided detailed documentation including cost justification for each of their proposed IT projects.[550] However, it considered that the specific requirements of the individual projects may lead to duplication, over-specification and/or incompatibility with the business IT environment and thereby reduce IT flexibility and lead to complex management and support requirements.[551]

P.6.4.1 CitiPower

Nuttall Consulting agreed with CitiPower that 2009 actual data should be included in relevant analysis.[552] Nuttall Consulting then stated that its recommendation on CitiPower's non-network IT capex for the forthcoming regulatory control period did not rely on the 2009 trend.[553]

Nuttall Consulting considered that CitiPower should expect change in the business environment and therefore better forecast the impact of potential changes on its IT capex program.[554] That is, CitiPower's IT system should be designed to be agile because agile technology is readily available and can be customised to CitiPower's specific circumstances.[555]

In Nuttall Consulting's view, CitiPower had not fully considered the complexity of its proposed IT capex program and the amount of IT changes able to be absorbed by the business, given that it did not have an agile IT environment.[556] However, Nuttall Consulting did not recommend the deferral or advancement of any specific proposed IT project on the basis that CitiPower would prioritise its capex program based on its own business needs.[557]

In relation to CitiPower's proposed AMI leveraged projects, Nuttall Consulting considered that no additional quantification or estimates were provided regarding costs and benefits and interaction between proposed expenditures and existing expenditure incentive mechanisms.[558] Therefore, Nuttall Consulting considered the proposed AMI leveraged projects proposed expenditures were not reasonable and did not meet the capex objectives.[559]

Table P.83 sets out Nuttall Consulting's recommendation on non-network IT capex for CitiPower in the forthcoming regulatory control period.

549 ibid., p. 47.
550 ibid., p. 48.
551 ibid., p. 48.
552 ibid., p. 88.
553 ibid., p. 88.
554 ibid., p. 88.
555 ibid., p. 89.
556 ibid., p. 90.
557 ibid., p. 89.
558 ibid., p. 90.
559 ibid., p. 90.

Table P.83 Nuttall Consulting recommendation on CitiPower non-network IT capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on CitiPower non-network IT capex	6.4	6.4	6.4	6.4	6.4	32.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.

Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 49, 90.

P.6.4.2 Powercor

Nuttall Consulting agreed with Powercor that 2009 actual data should be included in relevant analysis.[560] Nuttall Consulting then stated that its recommendation on Powercor's non-network IT capex for the forthcoming regulatory control period did not rely on the 2009 trend.[561]

Nuttall Consulting considered that Powercor should expect change in the business environment and therefore better forecast the impact of potential changes on its IT capex program.[562] That is, Powercor's IT system should be designed to be agile because agile technology is readily available and can be customised to Powercor's specific circumstances.[563]

In Nuttall Consulting's view, Powercor had not fully considered the complexity of its proposed IT capex program and the amount of IT changes able to be absorbed by the business, given that it did not have an agile IT environment.[564] However, Nuttall Consulting did not recommend the deferral or advancement of any specific proposed IT project on the basis that Powercor would prioritise its capex program based on its own business needs.[565]

In relation to Powercor's proposed AMI leveraged projects, Nuttall Consulting considered that no additional quantification or estimates were provided regarding costs and benefits and interaction between proposed expenditures and existing expenditure incentive mechanisms.[566] Therefore, Nuttall Consulting considered the proposed AMI leveraged projects proposed expenditures were not reasonable and did not meet the capex objectives.[567]

Table P.84 sets out Nuttall Consulting's recommendation on non-network IT capex for Powercor in the forthcoming regulatory control period.

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560 ibid., p. 161.
561 ibid., p. 161.
562 ibid., p. 161.
563 ibid., p. 162.
564 ibid., p. 163.
565 ibid., p. 162.
566 ibid., p. 163.
567 ibid., p. 163.

Table P.84 Nuttall Consulting recommendation on Powercor non-network IT capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on Powercor non-network IT capex	15.6	15.6	15.6	15.6	15.6	78.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 49, 163.

P.6.4.3 JEN

Nuttall Consulting considered JEN's forecast IT capex for the forthcoming regulatory control period was "relatively consistent with the historical IT expenditure and that Jemena [had] not shown a systemic bias in IT capex forecasting".[568] Therefore, although Nuttall Consulting considered JEN's IT infrastructure was not sufficiently agile, it recommended the AER accept JEN's revised regulatory proposal on non-network IT capex in the forthcoming regulatory control period.[569]

Table P.85 sets out Nuttall Consulting's recommendation on non-network IT capex for JEN in the forthcoming regulatory control period.

Table P.85 Nuttall Consulting recommendation on JEN non-network IT capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on JEN non-network IT capex	20.3	21.0	17.2	6.6	6.8	71.9

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 49, 122.

P.6.4.4 SP AusNet

Nuttall Consulting agreed with SP AusNet that 2009 actual data should be included in relevant analysis, however it considered that it was inappropriate to include 2010 data which had not yet been audited.[570] Nuttall Consulting also stated that its recommendations to the AER on SP AusNet's non-network IT capex in the forthcoming regulatory control period were based on consideration of whether the proposed expenditure was prudent and efficient and required to meet the capex objectives and not whether SP AusNet would be able to undertake a given volume of IT works in a given time period.[571] Further, Nuttall Consulting stated it had not made any recommendations or expressed any opinion as to which IT projects SP AusNet

568 ibid., p. 122.
569 ibid., p. 122.
570 ibid., p. 200.
571 ibid., p. 201.

should or should not complete in the forthcoming regulatory control period or whether SP AusNet should lease or purchase IT infrastructure.[572]

Whilst agreeing with SP AusNet's consultant Deloitte that the transition to cloud computing is complex, Nuttall Consulting noted that the existing IT infrastructure was equally complex.[573] Despite considering that SP AusNet did not have an agile IT system and that it had not properly accounted for the potential impacts of project delays or deferrals, Nuttall Consulting considered that individual IT projects proposed by SP AusNet were reasonable.[574] Nuttall Consulting did not comment on the capex efficiency regime to be applied to SP AusNet's non-network IT capex in the forthcoming regulatory control period.[575]

Table P.86 sets out Nuttall Consulting's recommendation on non-network IT capex for SP AusNet in the forthcoming regulatory control period.

Table P.86 Nuttall Consulting recommendation on SP AusNet non-network IT capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on SP AusNet non-network IT capex	18.0	18.0	18.0	18.0	18.0	90.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.

Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 49, 202.

P.6.4.5 United Energy

Nuttall Consulting considered that United Energy's underspend in the non-network IT capex category in the 2006–2010 regulatory period represented a prudent level of expenditure. That is, United Energy had not provided evidence that its expenditure in 2006–2010 was inadequate and resulting in adverse consequences.[576] However, Nuttall Consulting considered that United Energy's planning processes do not accommodate impacts of unforeseen project delays or deferrals in forecasting non-network IT capex requirements for the forthcoming regulatory control period.[577]

Nuttall Consulting considered that United Energy's IT systems could be more agile and noted that its comments related to the IT infrastructure and not to the IT application architecture.[578] It stated that its views on United Energy's non-network IT capex were not based on its perception of the size of United Energy's proposed IT capex program.[579]

572 ibid., p. 201.
573 ibid., p. 199.
574 ibid., p. 201.
575 ibid., p. 201.
576 ibid., p. 230.
577 ibid., p. 230.
578 ibid., p. 229.
579 ibid., p. 228.

Table P.87 sets out Nuttall Consulting's recommendation on non-network IT capex for United Energy in the forthcoming regulatory control period.

Table P.87 Nuttall Consulting recommendation on United Energy non-network IT capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on United Energy non-network IT capex	13.3	13.3	13.3	13.3	13.3	66.5

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.

Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 49, 231.

P.6.5 Issues and AER considerations

To inform its decision on each Victorian DNSP's non-network IT capex direct costs, it is important for the AER to be provided with evidence that enables it to provide a DNSP with an allowance that recovers at least the efficient costs it occurs in meeting the capex objectives in the forthcoming regulatory control period. In assessing the Victorian DNSPs' revised regulatory proposals on non-network IT capex, the AER has had regard to Nuttall Consulting's report as a basis for establishing the AER's view on the reasonableness of the Victorian DNSPs' proposals. The AER has also had regard to the capex factors (1) to (5) and , in particular, the actual and expected capex of the DNSP during the 2006–10 regulatory period (NER clause 6.5.7(e)(4)).

In respect of the prudency and efficiency of the Victorian DNSPs' proposed IT projects, the AER notes that Nuttall Consulting commented:[580]

> Each DNSP provided detailed cost justification and detailed documentation for each of their proposed IT projects. Many also included third party (independent) assessments of their projects.
>
> Nuttall Consulting does not dispute the DNSPs justifications for individual IT capital projects; in general these were comprehensive and appeared to be individually prudent and efficient. However, these individual project costs are made on the basis of very specific requirements related to a specific IT project. As a result, components could be duplicated, over-specified and/or incompatible with the rest of the IT environment, all of which would reduce flexibility, eliminate reuse/sharing of expensive components and lead to a more complex environment to manage [and] support.

The AER agrees with Nuttall Consulting that each Victorian DNSP provided IT strategy documentation setting out in detail its proposed projects and forecast annual project costings in the forthcoming regulatory control period. However, the AER notes that the documentation was high level and that the Victorian DNSPs stated that detailed business cases would be prepared closer to the forecast date of project

580 ibid., p. 48.

implementation.[581] However, as noted by Nuttall Consulting, the DNSPs have relied upon third parties to develop their forecast non-network IT capex project estimates. On this basis, the AER accepts that the proposed project costs are reasonable for individual non-network IT capex projects in the forthcoming regulatory control period. Therefore, the AER considers that, as proposed projects advance through the internal governance processes, it is likely that the total capex required to deliver the proposed projects as listed in the respective IT strategy documents may be lower than proposed by the Victorian DNSPs.

Regarding the Victorian DNSPs' submissions on the 'agility' of their IT systems, the AER notes Nuttall Consulting's observation that most Victorian DNSPs have already adopted some virtualisation functionality.[582] However, Nuttall Consulting also considered:[583]

> The [Victorian] DNSPs are not forecasting reasonable increases to the level of adoption of virtualisation technology. Whilst the exact level of adoption of virtualisation varied between DNSPs, overall the DNSPs have adopted minimal to low levels of virtualisation.

In their respective revised regulatory proposals, each Victorian DNSP has expressed the view that its investment in virtualisation has resulted in a level of IT agility appropriate to its particular circumstances.[584] The AER notes that SP AusNet was the only Victorian DNSP to submit a third-party opinion in support of its revised regulatory proposal on non-network IT capex. In support of SP AusNet, Deloitte commented:[585]

> The landscape of SP AusNet's infrastructure is typical of many organisations in the utilities industry that have embraced virtualisation and are providing agility capabilities in their IT environments.

The AER considers that Deloitte is well-placed to make such an observation given that it has advised a number of the Victorian DNSPs on their IT strategies and technology plans.[586] In its concluding comments on SP AusNet's IT agility, Deloitte expressed its view that:[587]

> The level of adoption and virtualisation evident in the SP AusNet IT Infrastructure Architecture allows for an appropriate level of agility.

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581 CHED Services, *Information Technology Strategic Plan 2010–2015*, 6 November 2009, p. 19; CitiPower, *Initial regulatory proposal*, pp. 138–139; Powercor, *Initial regulatory proposal*, pp. 134–135; JEN, *JEN IT Strategy & Asset Management Plan 2011–2015*, 19 November 2009, pp. 14–15; SP AusNet, *Information Technology Strategy (CY2011–2015): Electricity Distribution Network*, November 2009, pp. 44–45; United Energy, *Response to information requested 4 March 2010*, 23 March 2010.

582 Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 43.

583 ibid., p. 44.

584 CitiPower, *Revised regulatory proposal*, p. 324; Powercor, *Revised regulatory proposal*, pp. 314–315; JEN, *Revised regulatory proposal*, p. 170; SP AusNet, *Revised regulatory proposal*, pp. 147–148; United Energy, *Revised regulatory proposal*, p. 152.

585 Deloitte, *SP AusNet: Review of non-system IT capital expenditure*, 19 July 2010, p. 6.

586 Deloitte, *SP AusNet: Review of non-system IT capital expenditure*, 19 July 2010, p. 16; Deloitte, *United Energy Distribution: UED IT Capital Program Review*, Version 1.2, 10 November 2009, p. 3.

587 Deloitte, *SP AusNet: Review of non-system IT capital expenditure*, 19 July 2010, p. 8.

Whilst dismissing the relevance of cloud computing to the Victorian DNSPs, Deloitte has not explained what is an appropriate level of agility for the Victorian DNSPs. However, both United Energy and Deloitte commented that cloud computing was not appropriate to the Victorian DNSPs' particular circumstances. United Energy stated:

> [as the current chair of AEMO's] Energy Market Information Technology Reference Group … [United Energy] is not aware of any trends or obligation based drivers within the Australian electricity market to move towards a flexible/agile architecture based on "cloud computing" or "Infrastructure as a Service" services. … [United Energy] are not aware of any other market participants who utilise "cloud computing" or "Infrastructure as a Service" services to provide critical systems.

Deloitte supported United Energy's views in stating:[588]

> Given it is not advisable to implement solutions that require significant customisation and integration in the cloud environment, we do not believe a prudent operator in the circumstances of the DNSPs in the Victorian electricity industry should adopt the IaaS [Infrastructure as a Service] or cloud computing approach [as an enabler of agility in IT infrastructure environments] at this time – to do so would likely be inconsistent with the requirements of the National Electricity Rules (NER).

Therefore, on the basis of the Victorian DNSPs' submissions and Nuttall Consulting's report, the AER considers that each Victorian DNSP has implemented IT virtualisation, consistent with IT trends in the electricity distribution industry.

In regard to the impact of the mandated AMI rollout on the Victorian DNSPs' non-network IT capex in the 2006–10 regulatory period, the AER notes that:

- CitiPower's non-network IT activities were reduced from that in the 2001–05 regulatory period because it redirected its IT resources to implementation of the mandated AMI rollout[589]
- Powercor's non-network IT activities were reduced from that in the 2001–05 regulatory period because it redirected its IT resources to implementation of the mandated AMI rollout[590]
- JEN deferred its distribution management system so that it could implement its outage management system which uses the same Oracle software and it upgraded its CITRIX communications network[591]
- SP AusNet did not discuss the impact of the mandated AMI rollout on its 2006–10 non-network IT capex
- United Energy deferred replacement of applications such as SAP, CIS and WebMethods.[592]

588 ibid., p. 8.
589 CitiPower, *Revised regulatory proposal*, pp. 322–323.
590 Powercor, *Revised regulatory proposal*, p. 313.
591 JEN, *Revised regulatory proposal*, Appendix 8.9–JEN's IT Program, pp. 8–9.
592 United Energy, *Response to Nuttall Consulting information request*, 22 February 2010.

Further, in Deloitte's view:

> … the electricity distribution industry in Victoria is undergoing fundamental change with the advent of AMI.[593]
>
> …IT capex is affected by a rapidly changing technological environment, a forecasting approach that is inherently backward-looking is unsatisfactory as it cannot reflect current or future technological solutions.[594]

Therefore, the AER has concluded that it is not appropriate to consider the Victorian DNSPs' IT works programs in the 2006–10 regulatory period as being representative of the on-going necessary levels of non-network IT capex investment required to meet the capex objectives in the forthcoming regulatory control period. The AER also confirms its draft decision that there was no evidence of 'double counting' of IT capex amounts approved under the separate AER AMI determination and the proposed non-network IT capex in the forthcoming regulatory control period.

Having said that, the AER has considered the accuracy of the Victorian DNSPs' forecasts in respect of the forecast and actual non-network IT capex 2006–10 regulatory period. In this regard, the AER notes Deloitte's comments:[595]

> … in our view the fact that historic capital spend on non-system IT has not matched forecasts is more likely to be a function of the fact that non-system IT is fundamentally difficult to forecast. … The very nature of IT spending means that IT solutions and expenditure levels, particularly towards the end of a regulatory period, are extremely difficult to forecast some five years in the future. … SP AusNet's IT expenditure in the previous regulatory period is consistent with this premise – it was much closer to the regulatory forecasts in the earlier part of the regulatory period than the later.

The AER notes that Deloitte's comments are consistent with the observations in Nuttall Consulting's report.[596] The difficulty experienced by the Victorian DNSPs in forecasting their non-network IT capex requirements is also reflected in the expenditure variance of each Victorian DNSPs compared to its respective ESCV benchmark allowance as shown at table P.88.

593 Deloitte, *SP AusNet: Review of non-system IT capital expenditure*, 19 July 2010, p. 8.
594 ibid., p. 10.
595 ibid., p. 12.
596 Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, pp. 37–40, 47–48.

Table P.88 Variance between ESCV benchmark allowance and 2006–10 non-network IT capex (per cent)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
ESCV benchmark allowance	66.2	66.2	34.9	30.7	62.8
2006–10 expenditure	19.3	27.2	66.8	101.2	22.1
Variance (per cent)	– 70.8	– 58.9	91.4	229.6	– 64.8

Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010; Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010; JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010; SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010; United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.

As shown at table P.88, JEN and SP AusNet have overspent against their ESCV benchmark allowance. However, the AER considers that the over-expenditure was largely due to "one-off" events during the 2006–10 regulatory period:

- in the case of JEN:[597]
  - there has been great business disruption due to two changes of ownership
  - on acquisition in October 2006 by Alinta, large scale activity was ramped up in IT to catch up and modernise those projects were completed and capitalised from 2009 onwards.
- in the case of SP AusNet:[598]
  - IT infrastructure and back office systems previously accounted for as operating expenditure have been capitalised with expected $32 million ($2010) in 2006–10
  - AMI related expenditure accepted as part of the AMI budget application and forecast to be $30 million ($2010) has been included in 2006–10

Further, as noted by Deloitte and SP AusNet, the Victorian DNSPs do not have an incentive to overspend on their non-network IT capex allowances.[599] Rather, their incentive is to underspend the forecast.

Therefore, having regard to Nuttall Consulting and Deloitte's respective reports regarding the Victorian DNSPs' accuracy in forecasting future expenditure requirements, the AER considers that the forecasts of the DNSPs will be less reliable at the end of the regulatory period. However, in the absence of robust evidence of systemic bias in the forecasting of expenditure, the AER does not consider it

[597] JEN, *JEN IT Strategy & Asset Management Plan 2011–2015*, 19 November 2009, p. 22; JEN, *Revised regulatory proposal*, Appendix 8.9, 19 November 2009, p. 7–9.

[598] SP AusNet, *Information Technology Strategy (CY2011–2015): Electricity Distribution Network*, November 2009, p. 17.

[599] Deloitte, *SP AusNet: Review of non-system IT capital expenditure*, 19 July 2010, p. 11; SP AusNet, *Revised regulatory proposal*, p. 151.

appropriate to adjust the proposed expenditures in the forthcoming regulatory control period.

Therefore, for the reasons discussed above, the AER has accepted the Victorian DNSPs' proposed non-network IT capex direct costs in the forthcoming regulatory control period.

P.6.5.2 CitiPower

CitiPower's revised regulatory proposal reinstated the non-network IT capex amounts as per its initial regulatory proposal and therefore, the AER reconsidered the following information previously submitted by CitiPower in support of its initial regulatory proposal:

- initial regulatory proposal – sections 5.9 and 28.3 and attachments C0010, C0012 to C0015 inclusive (including Information Technology Strategic Plan)
- CitiPower's responses to AER and Nuttall Consulting requests for information.

The AER's responses to CitiPower's further comments in respect of the AER's draft decision are discussed below.

- As discussed at the beginning of section P.6.5:
  - the AER's final decision on the non-network IT capex direct costs has not been determined on the basis of historical non-network IT capex
  - the AER accepts that CitiPower has implemented IT virtualisation, consistent with IT trends in the electricity distribution industry.
- The AER considers its final decision on CitiPower's non-network IT capex direct costs has included an allowance for CitiPower's proposed replacement of its CIS system as a joint project between itself, Powercor and ETSA Utilities.
- In the case of CitiPower's proposed AMI leveraged projects, the AER maintains that it has considered the information provided in the PwC report submitted by CitiPower in support of the proposed project. Given that CitiPower will complete its AMI rollout by 31 December 2013 and is proposing to implement its AMI leveraged projects during 2012–15, the AER does not accept CitiPower's statement that:

> The AMI leveraged projects are only scheduled for completion in 2015. This eliminates the potential for any reinforcement capex deferral benefit to arise in the period 2011–15 and, thus also, the potential for such a benefit to be used to (partially) fund the implementation of the AMI leveraged projects in that period.[600]

[600] CitiPower, *Revised regulatory proposal*, p. 329; CitiPower, *Response to information requested 4 March 2010*, 12 March 2010; PriceWaterhouseCoopers, *CitiPower and Powercor AMI leverage projects: An assessment of the justifiable need for investment in additional AMI capabilities*, October 2009, p. 15.

That is, the AER considers it is possible that some reinforcement capex savings could be realised by project deferral during the forthcoming regulatory control period. However, the AER agrees that the proposed investment will allow it to access and use data available as a result of the mandated AMI rollout similar to non-network IT capex proposed by other Victorian DNSPs.[601] Therefore, the AER accepts the inclusion of this project in CitiPower's non-network IT capex in the forthcoming regulatory control period.

Table P.89 sets out CitiPower's revised non-network IT capex proposal and the AER's final decision.

Table P.89 Non-network IT capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower revised regulatory proposal	8.4	7.5	7.4	11.2	8.9	43.4
AER final decision	8.4	7.5	7.4	11.2	8.9	43.4

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.6.5.3 Powercor

Powercor's revised regulatory proposal reinstated the non-network IT capex amounts as per its initial regulatory proposal and therefore, the AER reconsidered the following information previously submitted by Powercor in support of its initial regulatory proposal:

- initial regulatory proposal – sections 5.9 and 28.3 and attachments P0010, P0012 to P0014 inclusive (including Information Technology Strategic Plan)
- Powercor's responses to AER and Nuttall Consulting requests for information.

The AER's responses to Powercor's further comments in respect of the AER's draft decision are discussed below.

- As discussed at the beginning of section P.6.5:
  - the AER's final decision on the non-network IT capex direct costs has not been determined on the basis of historical non-network IT capex
  - the AER accepts that Powercor has implemented IT virtualisation, consistent with IT trends in the electricity distribution industry.
- The AER considers its final decision on Powercor's non-network IT capex direct costs has included an allowance for Powercor's proposed replacement of its CIS system as a joint project between itself, CitiPower and ETSA Utilities.

[601] JEN, *Revised regulatory proposal*, Appendix 8.9–JEN's IT Program, pp. 45–48; SP AusNet, *Revised regulatory proposal*, p. 145.

- In the case of Powercor's proposed AMI leveraged projects, the AER maintains that it has considered the information provided in the PwC report submitted by Powercor in support of the proposed project. Given that Powercor will complete its AMI rollout by 31 December 2013 and is proposing to implement its AMI leveraged projects during 2012–15, the AER does not accept Powercor's statement that:

  > The AMI leveraged projects are only scheduled for completion in 2015. This eliminates the potential for any reinforcement capex deferral benefit to arise in the period 2011–15 and, thus also, the potential for such a benefit to be used to (partially) fund the implementation of the AMI leveraged projects in that period.[602]

  That is, the AER considers it is possible that some reinforcement capex savings could be realised by project deferral during the forthcoming regulatory control period. However, the AER agrees that the proposed investment will allow it to access and use data available as a result of the mandated AMI rollout similar to non-network IT capex proposed by other Victorian DNSPs.[603] Therefore, the AER accepts the inclusion of this project in Powercor's non-network IT capex in the forthcoming regulatory control period.

Table P.90 sets out Powercor's revised non-network IT capex proposal and the AER's final decision.

Table P.90 Non-network IT capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor revised regulatory proposal	22.4	19.2	17.5	26.3	20.1	106.4
AER final decision	22.4	19.2	17.5	26.3	20.1	106.4

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.6.5.4 JEN

JEN's revised regulatory proposal reinstated the non-network IT capex amounts as per its initial regulatory proposal and therefore, the AER reconsidered the following information previously submitted by JEN in support of its initial regulatory proposal:

- initial regulatory proposal – appendices 3.2 and 9.2 (JEN IT Strategy Asset Management Plan 2011–15)
- JEN's responses to AER and Nuttall Consulting requests for information.

602 Powercor, *Revised regulatory proposal*, p. 320; Powercor, *Response to information requested 4 March 2010*, 12 March 2010; PriceWaterhouseCoopers, *CitiPower and Powercor AMI leverage projects: An assessment of the justifiable need for investment in additional AMI capabilities*, October 2009, p. 15.

603 JEN, *Revised regulatory proposal*, Appendix 8.9–JEN's IT Program, pp. 45–48; SP AusNet, *Revised regulatory proposal*, p. 145.

At the time of its draft decision, the AER had considered the information provided by JEN and had sought to establish that the proposed projects and associated costs were reasonably required to meet the capex objectives.

As discussed at the beginning of section P.6.5, the AER accepts that JEN has implemented IT virtualisation, consistent with IT trends in the electricity distribution industry.

Table P.91 sets out JEN's revised non-network IT capex proposal and the AER's final decision.

Table P.91 Non-network IT capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN revised regulatory proposal	17.2	17.6	14.1	5.3	5.4	59.6
AER final decision	17.2	17.6	14.1	5.3	5.4	59.6

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.

Source: JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.6.5.5 SP AusNet

SP AusNet's revised regulatory proposal reinstated the non-network IT capex amounts as per its initial regulatory proposal and therefore, the AER reconsidered the following information previously submitted by SP AusNet in support of its initial regulatory proposal:

- initial regulatory proposal – section 6.12 and appendix F (Information Technology Strategy)
- SP AusNet's responses to AER and Nuttall Consulting requests for information.

At the time of its draft decision, the AER had considered the information provided by SP AusNet and had sought to establish that the proposed projects and associated costs were reasonably required to meet the capex objectives.

The AER's responses to SP AusNet's further comments in respect of the AER's draft decision are discussed below.

- As discussed at the beginning of section P.6.5:
  - the AER's final decision on the non-network IT capex direct costs has not been determined on the basis of historical non-network IT capex
  - the AER accepts that SP AusNet has implemented IT virtualisation, consistent with IT trends in the electricity distribution industry.
- The AER notes that its final decision has applied the same method in determining each of the Victorian DNSP's non-network IT capex direct costs in the forthcoming regulatory control period.

- The AER notes that its final decision has not commented on the Victorian DNSPs' respective IT ownership models and has not sought to micro-manage their commercial decisions.

- The AER considers that Nuttall Consulting's assessment did examine the relationship between IT applications and infrastructure and the AER notes that Nuttall Consulting commented:[604]

> Each DNSP provided detailed cost justification and detailed documentation for each of their proposed IT projects. Many also included third party (independent) assessments of their projects.

- The AER considers its final decision on SP AusNet's non-network IT capex direct costs has included an allowance for SP AusNet's proposed upgraded customer communications system.

The AER has also given consideration to SP AusNet's proposal to exclude a return of capital component and retain only the return on capital component for its non-network–other capex as a means to address its concern that it would be penalised if it overspent its non-network–other capex allowance as set out at chapter 9 (Opening asset base) of this final decision. In summary, the AER does not accept SP AusNet's proposal and will continue to apply both a return on and return of capital component to the non-network–other capex in the forthcoming regulatory control period.

Table P.92 sets out SP AusNet's revised non-network IT capex proposal and the AER's final decision.

Table P.92 Non-network IT capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet revised regulatory proposal	31.9	37.1	27.1	30.2	16.7	143.0
AER final decision	31.9	37.1	27.1	30.2	16.7	143.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.
Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1,* July 2010.

P.6.5.6 United Energy

United Energy's revised regulatory proposal reinstated the non-network IT capex amounts as per its initial regulatory proposal and therefore, the AER reconsidered the following information previously submitted by United Energy in support of its initial regulatory proposal:

- initial regulatory proposal – section 6.10 and appendix E-2 (UED IT Capital Program)

[604] Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 48.

- United Energy 's responses to AER and Nuttall Consulting requests for information.

At the time of its draft decision, the AER had considered the information provided by United Energy and had sought to establish that the proposed projects and associated costs were reasonably required to meet the capex objectives.

The AER's responses to United Energy's further comments in respect of the AER's draft decision are discussed below.

- The AER has accepted United Energy's updated costs relating to its proposed ERP–SAP Consolidation project.

- As discussed at the beginning of section P.6.5, the AER accepts that United Energy has implemented IT virtualisation, consistent with IT trends in the electricity distribution industry.

- The AER considers that its final decision on United Energy's proposed non-network IT capex recognises all of United Energy's projects in the forthcoming regulatory control period.

- The AER's considers that its final on United Energy's proposed non-network IT capex has not considered any projects others than those proposed by United Energy. That is, the AER has not considered that United Energy should anticipate and cost now IT applications that are not defined prior to the commencement of the forthcoming regulatory control period.

Table P.93 sets out United Energy's revised non-network IT capex proposal and the AER's final decision.

Table P.93 Non-network IT capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy revised regulatory proposal	23.5	36.5	27.6	16.0	7.2	111.0
AER final decision	23.5	36.5	27.6	16.0	7.2	111.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.

Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.6.6 AER conclusion

This section P.6 has assessed the direct costs of the proposed allowance for non-network IT capex which is one component of each Victorian DNSP's proposed total forecast capital expenditure. The AER considers that the direct costs determined in this section P.6 are consistent with the requirement in clause 6.5.7(c) of the NER that the forecast capital expenditure reasonably reflects the capital expenditure criteria.

This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs' total forecast capital expenditure.

That constituent decision, which should be read together with this appendix, is discussed at chapter 8.

Table P.94 sets out the AER's conclusion on the direct cost of each Victorian DNSP's revised regulatory proposals on non-network IT capex which it considers is consistent with forecast capital expenditure that reasonably reflects the capex criteria.

As explained at the beginning of this section P.6, in coming to this view, the AER has assessed the information submitted in support of each Victorian DNSP's revised regulatory proposals on non-network IT capex, having regard to the capex factors. Where relevant, the AER has made the minimum necessary change to the Victorian DNSPs' forecast non-network IT capex.

Table P.94 AER conclusion—Victorian DNSPs' 2011–15 non-network IT capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	8.4	7.5	7.4	11.2	8.9	43.4
Powercor	22.4	19.2	17.5	26.3	21.0	106.4
JEN	17.2	17.6	14.1	5.3	5.4	59.6
SP AusNet	31.9	37.1	27.1	30.2	16.7	143.0
United Energy	23.5	36.5	27.6	16.0	7.2	111.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes margins, overheads and real cost increases.

P.7 Non-network–other

This section considers the Victorian DNSPs' proposals on the non-network–other capex category.

As noted at the beginning of the capex chapter (chapter 8) of this final decision, each Victorian DNSP proposed allowances for non-network–other capex as a component of its total proposed forecast capital expenditure for the 2011–15 regulatory control period. The assessment of this component is relevant to determining whether the AER is satisfied that the total proposed forecast capital expenditure or its estimate of the required capital expenditure reasonably reflects the capital expenditure criteria.

Specifically, this section assesses the proposed allowances and what the level of efficient direct cost expenditure for non-network–other capex which a prudent operator, in the circumstances of each Victorian DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capital expenditure objectives.

Therefore, this section gives the reasons for the AER's final decision in respect of the direct costs relating to the Victorian DNSPs' respective revised regulatory proposals on non-network–other capex.

That is, in accordance with NER cl.6.12.2, this section sets out the basis and rationale for the AER's final decision including:[605]

- details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the AER
- the values adopted by the AER for the input variable in any calculations and formulae, including:
  - whether those values have been taken or derived from the Victorian DNSP's initial or revised regulatory proposals, and
  - if not, the rationale for the adoption of those values
- details of any assumptions made by the AER in undertaking any material and quantitative analyses
- reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretions, as referred to in chapter 6 of the NER, for the purposes of the AER's final decision.

Approach

Where a Victorian DNSP accepted the AER's draft decision on the direct costs for the non-network–other capex, the AER has approved that same direct cost amount(s) in its final decision.

Where a Victorian DNSP did not accept the AER's draft decision on the non-network–other capex direct costs, the AER has considered whether the revised regulatory proposal in respect of that proposed capex reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant Victorian DNSP would require to meet the capex objectives.

That is, having regard to the capex factors set out at NER cl.6.5.7(e), and particularly:

- the information included in or accompanying the building block proposal
- submissions received in the course of consulting on the building block proposal
- analysis undertaken by or for the AER and published before the distribution determination is made in its final form

[605] NER, clause 6.12.2.

- benchmark capital expenditure that would be incurred by an efficient distribution DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods

the AER has considered whether the proposed projects are in accordance with good industry practice including whether:

- there is a justifiable need for the proposed capex
- the proposed projects have been objectively and competently analysed to a standard that is consistent with good industry practice
- the proposed projects align with strategic capex plans and policies.

The AER sought explanation of the drivers of any proposed step changes in the non-network–other capex. The historical underlying trend in expenditure in the non-network–other capex was used as the starting point to assess whether a step change (increase or decrease) in expenditure had been proposed. However, given that the historical trend cannot completely determine future requirements, the AER requested the Victorian DNSPs to provide relevant economic analysis which clearly demonstrated the need to undertake the proposed projects in the forthcoming regulatory control period. The AER expected the analysis would demonstrate how engineering judgements had been translated into step changes in expenditure and be supported by cost-benefit analysis including options analysis. Having said that, the AER also expected the analysis would be appropriate in respect of the materiality of the proposed project expenditures as a proportion of the total capex for non-network–other.

The AER must allow each Victorian DNSP adequate funding to recover at least its respective efficient costs of providing direct control services. The AER is also aware that each Victorian DNSP must also satisfy safety and other regulatory and legislative obligations while managing its respective networks in accordance with good electricity practices. Therefore, in assessing each Victorian DNSP's proposed expenditures in non-network–other capex, the AER considered:

- whether the proposed projects aligned with strategic capex plans and policies
- changes in timing have been considered to ensure prudent decision-making
- processes or systems for project approval reflected good governance and business practices for undertaking capital projects
- cost-estimating processes incorporate feed-back from specific experience.

Where the AER has not accepted a Victorian DNSP's revised regulatory proposal, in respect of the direct costs of projects proposed in non-network–other capex, the AER has made the minimum necessary change to the Victorian DNSP's forecast capex direct cost expenditure.

The AER's assessment and final decision on a realistic expectation of the demand forecast and costs inputs required to achieve the capex objectives are set out at chapter 5 and appendix K respectively of this final decision. The AER's final decision on the total capex reasonably required by each Victorian DNSP is set out at chapter 8 and includes amounts for the direct costs (as set out in this appendix) for non-network–other capex, as adjusted for overheads, real cost increases and margins.

P.7.1 AER draft decision

The AER considered that the Victorian DNSPs retained discretion to prioritise their work programs and allocate their resources to meet customer requirements while managing and operating their networks in accordance with good electricity industry practice. That is, the Victorian DNSPs had at times over or underspent relative to the ESCV benchmark allowance on the basis of their own assessment of whether it was efficient to do so.

The historical underlying trend of capex was used by the AER as the starting point for assessing the reasonableness of the proposed non-network–other capex. In identifying the underlying trend, the AER considered data for 2004 to 2008 inclusive. That is, the 2009 and 2010 data provided by the Victorian DNSPs was considered to be forecast data and therefore not considered to be part of the historical trend.

P.7.1.1 CitiPower

The AER considered that CitiPower's proposed capex was consistent with a continuation of the historical capex in this cost category. Therefore, the AER accepted CitiPower's proposed capex amounts.

Table P.95 sets out CitiPower's initial proposed non-network–other capex and the AER's draft decision.

Table P.95 Non-network—other capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower initial regulatory proposal	3.2	3.6	3.2	3.2	3.2	16.4
AER draft decision	3.2	3.6	3.2	3.2	3.2	16.4

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 426, 433.

P.7.1.2 Powercor

Powercor's proposed expenditures included amounts relating to replacement of mobile cranes in order to achieve compliance with Australian Standards AS1418 and AS2250.5 (Cranes Hoist & Winches–Safe Use–Part 5 Mobile Cranes). The AER noted that Australian Standard AS2550.5 was introduced in 2004 and Powercor had stated that its estimated project expenditure was based on a catch up cost to comply with safety requirements for cranes to accord with the Australian Standards. Powercor indicated that a number of the mobile cranes would be replaced in the forthcoming regulatory control period, however, it did not provide information regarding the number and the timing of the proposed crane replacements. Therefore, the AER did not accept Powercor's proposed capex amounts for the project and substituted 50 per cent of the proposed project amount in its place as the AER's best estimate of Powercor's likely expenditure on mobile cranes in the forthcoming regulatory control period.

Table P.96 sets out Powercor's initial proposed non-network–other capex and the AER's draft decision.

Table P.96 Non-network—other capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor initial regulatory proposal	16.6	17.6	16.7	16.8	16.8	84.5
AER draft decision	8.0	8.0	8.0	8.0	8.0	40.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.

Source: AER, *Victorian distribution determination 2011–15,* Draft decision, June 2010, pp. 426, 433.

P.7.1.3 JEN

JEN's proposed expenditures included amounts relating to purchases of land for proposed zone substation developments in the forthcoming regulatory control period and beyond and for the merger and relocation of its Broadmeadows and Sunshine depots. The AER noted that JEN was the only Victorian DNSP to include land associated with zone substation developments in this capex category. The AER considered that the relevant amounts should be transferred from the non-network–other capex category to the reinforcement capex category. As a result, these projects and their associated expenditures were considered as part of JEN's proposed reinforcement capex. Further, the AER considered that capex was likely to be incurred in the forthcoming regulatory control period for the relocation of JEN's Sunshine depot. However, the AER was unable to identify an amount for this project separate to the amount proposed for the relocation of the Broadmeadows depot. The AER did not accept JEN's proposed capex amounts for this project and substituted zero capex in its place.

Table P.97 sets out JEN's initial proposed non-network–other capex and the AER's draft decision.

Table P.97 Non-network—other capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN initial regulatory proposal	17.2	8.1	6.8	4.0	5.5	41.7
AER draft decision	3.3	2.6	3.4	3.5	4.0	16.8

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 426, 433.

P.7.1.4 SP AusNet

SP AusNet explained that it unwound its contracting arrangements with Tenix Alliance during 2006–10 and the capex spike in 2008 related to its decision to purchase rather than lease motor vehicles. SP AusNet has since reverted to leasing its motor vehicles. Given that SP AusNet proposed to continue leasing its vehicles in the forthcoming regulatory control period, the AER substituted $4.2 million ($2010, fully absorbed cost) in place of $15.25 million ($2010, fully absorbed cost) actual expenditure reported in this cost category in 2008 to determine the historical expenditure trend. Therefore, the AER did not accept SP AusNet's proposed capex amounts and substituted amounts based on a continuation of the historical expenditure trend in this capex category.

Table P.98 sets out SP AusNet's initial proposed non-network–other capex and the AER's draft decision.

Table P.98 Non-network—other capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet initial regulatory proposal	9.6	6.5	6.2	6.3	6.2	34.7
AER draft decision	3.6	3.6	3.6	3.6	3.6	18.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 426, 433.

P.7.1.5 United Energy

The AER considered that United Energy's proposed capex was consistent with a continuation of the historical capex in this cost category. Therefore, the AER accepted United Energy's proposed capex amounts.

Table P.99 sets out United Energy's initial proposed non-network–other capex and the AER's draft decision.

Table P.99 Non-network—other capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy initial regulatory proposal	2.1	4.7	1.9	2.7	1.8	13.1
AER draft decision	2.1	4.7	1.9	2.7	1.8	13.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.
Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 426, 433.

P.7.2 Victorian DNSP revised regulatory proposals

P.7.2.1 CitiPower

CitiPower stated it did not contest the AER's draft decision with respect to non-network–other capex.[606] However, it did not accept the draft decision because it considered the AER should include 2009 actual data in forecasting the environmental, safety and legal capex in the forthcoming regulatory control period by reference to historical expenditure.[607]

Table P.100 sets out the AER's draft decision and CitiPower's revised non-network–other capex proposal.

Table P.100 Non-network—other capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	3.2	3.6	3.2	3.2	3.2	16.4
CitiPower revised regulatory proposal	2.9	3.2	2.9	3.0	3.0	14.9

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 433.

P.7.2.2 Powercor

Powercor submitted that the AER should include 2009 actual data in forecasting the non-network–other capex in the forthcoming regulatory control period by reference to historical expenditure.[608]

Powercor also stated:[609]

606 CitiPower, *Revised regulatory proposal*, p. 330.
607 ibid., p. 321.
608 Powercor, *Revised regulatory proposal*, p. 321.

- this capex category captured projects of a non-engineering nature and therefore it was unclear how engineering judgement is a factor in determining a step-change in expenditure for the projects

- this capex category includes items such as motor vehicles, general equipment, and office furniture and that it is difficult to apply a separate cost-benefit analysis for every chair and vehicle. Accordingly, Powercor had demonstrated the need for investment for discrete projects such as the replacement of mobile cranes

- the AER's comments that Powercor had not demonstrated why it could not manage existing programs and associated risks within the current level of expenditure suggested that the AER proposed to approve expenditure commensurate with the current level of expenditure. Powercor stated that the AER had provided a capex amount significantly below actual historical expenditure.

Table P.101 sets out the AER's draft decision and Powercor's revised non-network–other capex proposal.

Table P.101 Non-network—other capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	8.0	8.0	8.0	8.0	8.0	40.0
Powercor revised regulatory proposal	16.6	17.6	16.7	16.8	16.8	84.6

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 433.

P.7.2.3 JEN

JEN stated that the AER's approach in arriving at the non-network–other capex amounts was not clear.[610] JEN assumed that the amounts referred to its vehicles, tools and test equipment expenditures and that expenditure for proposed zone substation land purchases and the Broadmeadows depot redevelopment had been excluded.

JEN confirmed its belief that zone substation property purchases should be allocated to non-network–other capex because the purchases would be made ahead of time in support of its future requirement for new zone substations.[611] In relation to the proposed Broadmeadows depot relocation project, JEN stated that safety, asbestos, oil containment and access risks at the current site have resulted in its proposal to abandon the site and build a new depot in an adjacent location.[612]

609 ibid., p. 301.
610 JEN, *Revised regulatory proposal*, p. 172.
611 ibid., p. 172.
612 ibid., pp. 173–174.

Table P.102 sets out the AER's draft decision and JEN's revised non-network–other capex proposal.

Table P.102 Non-network—other capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	3.3	2.6	3.4	3.5	4.0	16.8
JEN revised regulatory proposal	17.3	21.6	6.8	4.0	5.5	55.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15,* Draft decision, June 2010, p. 433.

P.7.2.4 SP AusNet

SP AusNet submitted that the non-network–other capex is related to the size and scale of the network in a manner similar to the opex allowance.[613] Therefore, it applied a 'scale escalator' to the amounts set out in the AER's draft decision, as has been applied to its opex allowance.[614]

SP AusNet also expressed concern that it would be penalised if it overspent its non-network–other capex allowance. That is, its RAB for the 2016–20 regulatory control period will be reduced by an amount equal to the actual (and not forecast) depreciation. Therefore, it proposed that the capex efficiency regime to be applied to its non-network–other capex exclude a return of capital component and retain only the return on capital component.[615]

Table P.103 sets out the AER's draft decision and SP AusNet's revised non-network–other capex proposal.

Table P.103 Non-network—other capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	3.6	3.6	3.6	3.6	3.6	18.2
SP AusNet revised regulatory proposal	3.7	3.7	3.8	3.9	3.9	19.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.
Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15,* Draft decision, June 2010, p. 433.

613 SP AusNet, *Revised regulatory proposal*, p. 153.
614 ibid., p. 153.
615 ibid., p. 153.

P.7.2.5 United Energy

United Energy noted that the AER had accepted its initial regulatory proposal.[616] It then stated it had reviewed its initial regulatory proposal and had revised the component relating to its fleet requirements for the forthcoming regulatory control period. United Energy considered its revised forecasts remained consistent with its expenditure levels in the 2006–2010 regulatory period.[617]

Table P.104 sets out the AER's draft decision and United Energy's revised non-network–other capex proposal.

Table P.104 Non-network—other capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
AER draft decision	2.1	4.7	1.9	2.7	1.8	13.2
United Energy revised regulatory proposal	8.8	4.3	2.5	2.8	2.5	20.9

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.

Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.
AER, *Victorian distribution determination 2011–15,* Draft decision, June 2010, p. 433.

P.7.3 Submissions

The AER received a submission from the Energy Users Coalition of Victoria (EUCV) on the non-network–other capex proposed by the Victorian DNSPs.

The EUCV supported the AER's approach and considered it was "detailed, robust and reflect[ed] the actuality of what the [Victorian DNSPs] themselves considered to be appropriate investment in these areas".[618]

P.7.4 Consultant review

In the case of non-network–other capex, Nuttall Consulting assessed only the matters raised in the revised regulatory proposals submitted by JEN and SP AusNet.

P.7.4.1 CitiPower

Nuttall Consulting did not assess CitiPower's revised regulatory proposal on non-network–other capex because it did not assess CitiPower's initial regulatory proposal on non-network–other capex.[619]

616 United Energy, *Revised regulatory proposal*, p. 155.
617 ibid., p. 155.
618 Energy Users Coalition of Victoria, *Australian Energy Regulator Victorian Electricity Distribution Revenue Reset AER Draft Decisions and Revised Regulatory Proposals on CitiPower, Jemena, Powercor, SP AusNet and United Energy Applications: A response by Energy Users Coalition of Victoria*, August 2010, p. 22.

P.7.4.2 Powercor

Nuttall Consulting did not assess Powercor's revised regulatory proposal on non-network–other capex because it did not assess Powercor's initial regulatory proposal on non-network–other capex.[620]

P.7.4.3 JEN

Nuttall Consulting stated it had considered JEN's proposed zone substation land purchases as part of its assessment of JEN's proposed reinforcement capex.[621]

Nuttall Consulting's findings on JEN's proposed project to relocate its Broadmeadows depot were:[622]

- the proposed project timing is optimistic and not likely to eventuate because JEN's proposed work plan is already behind schedule
- JEN's initial regulatory proposal for the project was $15.3 million ($2010) whereas its revised regulatory proposal was for $30 million ($2010). Nuttall Consulting had not received any information explaining the increased expenditure
- JEN had identified but not quantified operating benefits likely to arise from the proposed project.

As a result, Nuttall Consulting considered JEN's initial regulatory proposal was appropriate for the project and that the amount should be spread across 2011 and 2012 to account for project delays.[623]

Table P.105 sets out Nuttall Consulting's recommendation on JEN's proposed Broadmeadows depot relocation project included in non-network–other capex in the forthcoming regulatory control period.

Table P.105 Nuttall Consulting recommendation on JEN's Broadmeadows depot relocation project included in non-network—other capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on JEN's Broadmeadows depot relocation project included in non-network–other capex	7.1	7.0	–	–	–	14.1

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.

Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 125.

619 Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 90.
620 ibid., p. 163.
621 ibid., p. 122.
622 ibid., pp. 122–124.
623 ibid., pp. 125–126.

P.7.4.4 SP AusNet

Nuttall Consulting considered SP AusNet's application of a scale escalator to its revised regulatory proposal on non-network–other capex in the forthcoming regulatory control period. Nuttall Consulting considered that it was more appropriate to use network growth together with customer numbers rather than employee numbers as a proxy for growth in non-network–other capex.[624] However, it commented:

> … the use of network growth and customer numbers as a proxy for growth in the non-network other capex category does not make allowance for any productive or dynamic efficiencies.[625]

and therefore stated that its recommendation on non-network–other capex for SP AusNet in the forthcoming regulatory control period had not been adjusted for productive or dynamic efficiencies.[626]

Nuttall Consulting's assessment did not take into account:

- the appropriateness of application of a scale escalator to non-network–other capex in the forthcoming regulatory control period[627]
- the capex efficiency regime to be applied to SP AusNet's non-network–other capex in the forthcoming regulatory control period.[628]

Table P.106 sets out Nuttall Consulting's recommendation on non-network–other capex for SP AusNet in the forthcoming regulatory control period.

Table P.106 Nuttall Consulting recommendation on SP AusNet non-network—other capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Nuttall Consulting recommendation on SP AusNet non-network–other capex	3.7	3.7	3.8	3.9	3.9	19.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.

Source: Nuttall Consulting, *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, 22 October 2010, p. 203.

P.7.4.5 United Energy

Nuttall Consulting did not assess United Energy's revised regulatory proposal on non-network–other capex because it did not assess United Energy's initial regulatory proposal on non-network–other capex.[629]

[624] ibid., p. 203.
[625] ibid., p. 203.
[626] ibid., p. 203.
[627] ibid., pp. 202–203.
[628] ibid., p. 203.
[629] ibid., p. 231.

P.7.5 Issues and AER considerations

P.7.5.1 Use of historical actual expenditure to forecast capex requirement in forthcoming regulatory control period

The AER agrees with the Victorian DNSPs that 2009 data should be used in historical expenditure analysis because audited 2009 regulatory accounts are now available.

P.7.5.2 CitiPower

CitiPower stated it did not contest the AER's draft decision with respect to non-network–other capex, however, it considered the AER should include 2009 actual data in its trend analysis and in forecasting the environmental, safety and legal capex required in the forthcoming regulatory control period by reference to historical expenditure.[630] The AER has included 2009 actual data in its analysis.

Table P.107 sets out CitiPower's revised non-network–other capex proposal and the AER's final decision.

Table P.107 Non-network—other capex—direct cost—CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower revised regulatory proposal	2.9	3.2	2.9	3.0	3.0	14.9
AER final decision	2.9	3.2	2.9	3.0	3.0	14.9

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes CitiPower's proposed margins, overheads and real cost increases.
Source: CitiPower, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.7.5.3 Powercor

Powercor submitted that the AER should include 2009 actual data in forecasting the SCADA and network control capex in the forthcoming regulatory control period by reference to historical expenditure.[631] The AER has included 2009 actual data in its analysis.

Powercor's further comments in respect of the AER's draft decision are discussed below.[632]

- Powercor considered that it was not clear why engineering judgement was a factor in determining a step change in non-network–other expenditure.

  The AER considers the application of engineering (or otherwise technical) judgement is a factor in determining step changes in expenditure where that expenditure relates to engineering/technical projects and not otherwise. Given that Powercor had submitted a report by the consulting mechanical engineering firm Wenn Wilkinson & Associates in relation to the proposed project to replace

[630] CitiPower, *Revised regulatory proposal*, p. 321.
[631] Powercor, *Revised regulatory proposal*, p. 321.
[632] ibid., p. 321.

mobile cranes, the AER considered that engineering/technical judgement was required in consideration of this project.

- In Powercor's view, it is difficult to apply a separate cost-benefit analysis for every chair and vehicle in this capex category. However, Powercor considered it had demonstrated the need for the proposed expenditure in the case of discrete projects such as that proposed for replacement of mobile cranes.

  The AER considers it is not necessary for Powercor to prepare a cost-benefit analysis for every chair and vehicle in the non-network–other capex category. In the case of Powercor's proposed replacement of mobile cranes, the AER considers that the supporting documentation provided by Powercor did not demonstrate the need for the proposed expenditure in the forthcoming regulatory control period. Further, in response to an AER information request, Powercor stated that it had not prepared a business case to support this project on the basis that it was required to achieve compliance with Australian Standards.[633] The AER recognises that complying with all applicable regulatory obligations or requirements associated with the provision of standard control services is a capex objective. However, the AER considers that the limited information provided by Powercor did not demonstrate the need for the proposed mobile crane replacement expenditure and, instead, confirmed the need for major inspections to be completed on crane borers and elevating work platforms.[634]

- Powercor considered the commentary in the AER's draft decision in respect of its non-network–other capex suggested that the AER had at least intended to approve capex commensurate with Powercor's historic level of expenditure.

  In coming to its draft decision, the AER had sought explanation of any proposed step changes relative to historic levels of expenditure in the non-network–other capex category. In this regard, the AER noted that Powercor had identified the proposed replacement of its mobile cranes as a new and material project which would be undertaken in the forthcoming regulatory control period. Irrespective of the historic level of expenditure, the AER considers it must allow adequate funding to Powercor to at least recover the efficient costs of providing direct control services in the forthcoming regulatory control period.

As Powercor's revised regulatory proposal reinstated the non-network–other capex amounts as per its initial regulatory proposal, the AER reconsidered the following information previously submitted by Powercor in support of its initial regulatory proposal:

- initial regulatory proposal – sections 5.9 and 28.1

- Powercor's responses to information requests from Nuttall Consulting and the AER.[635]

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633 Powercor, *Response to information requested 4 March 2010*, 12 March 2010.

634 Powercor, *Initial regulatory proposal*, pp. 136, 139, 411–412; Powercor, *Initial regulatory proposal*, Attachment P0185 (report by Wenn Wilkinson & Associates dated 4 May 2009).

635 Powercor, *Response to information requested 4 March 2010*, 12 March 2010; Powercor, *Response to information requested 17 August 2010*, 26 August 2010.

Powercor did not provide any new or additional information in relation to its proposed non-network–other capex as part of its regulatory proposal. Therefore, the AER requested Powercor to provide further information in support of its proposed expenditure on mobile cranes. In its response, Powercor stated:

- the information provided in the material project template at chapter 28 of its initial regulatory proposal and
- attachment P0185 (Wenn Wilkinson & Associates report on inspection requirements for crane borers) to the initial regulatory proposal

together comprised the information which it considered demonstrated to the AER the need for the proposed replacement of its mobile cranes.[636] Powercor later provided a spreadsheet setting out its calculation of the direct cost of the proposed project although it did explain the basis of the unit cost information used in the calculation.[637]

The AER does not consider the information submitted by Powercor at the time of its initial regulatory proposal and the spreadsheet calculation of the direct costs of the proposed project justifies the need to replace the mobile cranes. In particular, the AER notes that the Wenn Wilkinson & Associates report states that major inspections should be performed on Powercor's crane borers.[638] Therefore, the AER has not approved the amount of $13.6 million ($2010, direct cost) proposed by Powercor in respect of the proposed project to replace mobile cranes. Instead, the AER has substituted an amount of $3.6 million ($2010, direct cost) consistent with Powercor's expenditure in the 2006–2010 regulatory period on mobile cranes.[639]

Table P.108 sets out Powercor's revised non-network–other capex proposal and the AER's final decision.

Table P.108 Non-network—other capex—direct cost—Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor revised regulatory proposal	16.6	17.6	16.7	16.8	16.8	84.6
AER final decision	14.6	15.6	14.7	14.9	14.7	74.5

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes Powercor's proposed margins, overheads and real cost increases.
Source: Powercor, *Revised regulatory proposal–RIN template 2.1*, July 2010.

636 Powercor, *Response to information requested 17 August 2010*, 26 August 2010.
637 Powercor, *Response to information requested 17 August 2010*, 17 September 2010.
638 Powercor, *Initial regulatory proposal*, Attachment P0185 (report by Wenn Wilkinson & Associates dated 4 May 2009), p. 7.
639 Powercor, *Response to information requested 17 August 2010*, 17 September 2010.

P.7.5.4 JEN

As JEN's revised regulatory proposal reinstated the non-network–other capex amounts as per its initial regulatory proposal, the AER reconsidered the following information previously submitted by JEN in support of its initial regulatory proposal:

- initial regulatory proposal – appendix 3.2
- revised regulatory proposal – section 8.10, appendices 8.37 and 8.38
- JEN's response to AER and Nuttall Consulting information requests.

In particular, the AER requested JEN provide information supporting the proposed 32.4 per cent increase to the $41.7 million ($2010) proposed in its initial regulatory proposal. Table P.109 summarises JEN's proposed programs/projects in the non-network–other capex category.

Table P.109 Non-network—other capex proposed projects—JEN

Proposed program/project	AER comment
Zone substation land purchases	Transferred to reinforcement capex
Broadmeadows and Sunshine depots merger and relocation	Retained in non-network–other capex
Tools and equipment	Retained in non-network–other capex
Vehicles	Retained in non-network–other capex

Source: JEN, *JEN Response to AER Information Request on SCADA and Network Control, Environment, Safety, Legal (ESL), Non-network – IT and Non-network – other capex*, email dated 16 March 2010; JEN, *JEN Electricity Networks (Vic) Ltd Capital and Operational Work Plan (COWP)*, November 2009, p. 82; JEN, response August 201], JEN, *Revised regulatory proposal–RIN template 2.1*, July 2010; AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 433.

In its draft decision, the AER noted that JEN was the only Victorian DNSP to include zone substation land purchases in the non-network–other capex category. As the AER considered that land purchases for proposed zone substations relates to network activities, it transferred JEN's proposed zone substation land purchases projects from the non-network–other capex category to the reinforcement capex category.[640] Further, the AER notes that JEN includes zone substation land purchases in its business cases when assessing new zone substation developments.

In its response to the AER's information request, JEN stated that its most recent zone substation land purchase was in 2000 for its Coolaroo zone substation.[641] This land purchase has been retained in the non-network–other capex category and JEN considered that consistent treatment necessitates that its zone substation land purchases proposed in the forthcoming regulatory control period also be included in this capex category.

640 AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 431.
641 JEN, *Response to information requested 17 August 2010*, 30 August 2010.

The AER has not accepted JEN's proposal to include zone substation land purchases in the non-network–other capex category because the AER considers zone substation land relates to network activities. Therefore, the AER has transferred the proposed zone substation land purchases to the reinforcement capex category from the non-network–other capex category. The AER has also transferred the proposed zone substation land purchases from the non-network–other category to the distribution assets category in both JEN's regulatory asset base and JEN's regulatory tax asset base.

In the case of JEN's proposed merger and relocation of its Broadmeadows and Sunshine depots, the AER has considered the information JEN provided in its revised regulatory proposal at appendices 8.37 and 8.38. The AER notes JEN's consultants' assessment that the current Broadmeadows site fails to meet a range of legislation and codes.[642] In view of this assessment, JEN stated:

> The do as little as possible option is not acceptable as there are serious problems associated with safety, asbestos, oil containment and access risks.[643]

Although this statement suggests that JEN will proceed with the proposed relocation of the depot irrespective whether the AER approved the proposed project and/or irrespective of the quantum of any amount approved by the AER for this project, the AER notes that JEN has also stated:

> …it is unlikely that the project will be able to receive internal approval until the AER approves the expenditure. If the AER is unwilling to approve the expenditure before the project receives internal approval, a 'double bind' results.[644]

The AER requested information from JEN confirming its progress against the timeline for the proposed depot merger and relocation as set out in JEN's revised regulatory proposal at appendix 8.37. In its response, JEN confirmed that final negotiations and procurement of land for the new depot were expected to be finalised by December 2010.[645] JEN also confirmed there had been a change to the timing of the proposed project relative to the initial regulatory proposal and this was reflected in JEN's revised regulatory proposal in the shift of expected project direct costs from 2010 into the forthcoming regulatory control period.[646] The AER notes that appendix 8.37 to JEN's revised regulatory proposal states that, subject to project approval in July 2010 and commencement in August 2010, the depot site selection and land procurement will be finalised by December 2010 and that preliminary design and planning approval, building contractor selection and commencement of construction will occur in March 2011.[647]

[642] JEN, *Revised regulatory proposal*, pp. 173–174.
[643] ibid., p. 173.
[644] JEN, *Revised regulatory proposal*, Appendix 7.2 JEN Step changes—20 July 2010, pp. 61–62.
[645] JEN, *Response to information requested 17 August 2010*, 30 August 2010.
[646] JEN, *Response to information requested 10 September 2010*, 16 September 2010.
[647] JEN, *Revised regulatory proposal*, Appendix 8.37 Internal Memorandum - Replacement of JEN Broadmeadows depot—20 July 2010, Section 5.

JEN provided the following information in relation to the project costs:[648]

	2010	2011	2012
JEN initial regulatory proposal ($'m, 2010–direct cost)	13.8	13.4	–
JEN revised regulatory proposal ($'m, 2010–direct cost)	0.4	13.4	13.4

Source: JEN, *Response to information requested 10 September 2010*, 16 September 2010.

JEN has not explained what has happened to $13.4 million ($2010, direct cost) it had allocated to spend in 2010 on the depot merger and relocation project and why its revised regulatory proposal was seeking that same amount in the year 2011. JEN has stated that "[The non-network–other costs information provided by JEN] shows that the only difference between the direct cost capex in JEN's original proposal and in JEN's revised regulatory proposal is a change in timing of the Broadmeadows and Sunshine depots merger relocation".[649] The information provided by JEN suggests that it has deferred capex of $13.4 million ($2010, direct cost) from 2010 to 2011 and, as a result, reallocated the proposed amount of $13.4 million ($2010, direct cost) from 2011 to 2012. The AER considers that it is reasonable to expect that the amount of $13.4 million ($2010, direct cost) which JEN had allocated to the project in 2010 would be available to spend on the project in 2011. Therefore, the AER has not approved the amounts of $13.4 million ($2010, direct cost) proposed by JEN in each of the years 2011 and 2012 in respect of the proposed depot merger and relocation project. Instead, the AER has substituted an amount of $0 million ($2010, direct cost) in 2011 and $13.4 million ($2010, direct cost) in 2012.

Table P.110 sets out JEN's revised non-network–other capex proposal and the AER's final decision.

Table P.110 Non-network—other capex—direct cost—JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN revised regulatory proposal	17.3	21.6	6.8	4.0	5.5	55.2
AER final decision	3.4	16.1	3.4	3.5	4.0	30.5

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes JEN's proposed margins, overheads and real cost increases.
Source: JEN, *Revised regulatory proposal*, RIN template 2.1, July 2010.

P.7.5.5 SP AusNet

SP AusNet's stated: [650]

> … the Non-Network Other capex allowance is related to the size and scale of the network in manner similar to the opex allowance. Therefore, the

648 JEN, *Response to information requested 10 September 2010*, 16 September 2010.
649 ibid.
650 SP AusNet, *Revised regulatory proposal*, p. 153.

allowance needs to be adjusted to be consistent with network growth and increased customer numbers.

The AER requested SP AusNet to explain its application of a scale escalator. SP AusNet responded that it had taken the AER's draft decision direct costs values and "escalated by the customer number growth of 1.8% pa for the period".[651]

The AER notes that the opex allowance is established using a 'base year' opex allowance which has been adjusted, including for scale increases in the network. In contrast, the non-network–other capex allowance has been established having given consideration for the DNSP's 'bottom-up' build of forecast non-network–other capex for each regulatory year of the forthcoming regulatory control period. Further, the AER's decision on the non-network–other capex discussed in this appendix relates to the direct costs which are then adjusted for cost increases (such as for labour and materials), direct and indirect overheads and margins as part of determining the total capex for SP AusNet for the forthcoming regulatory control period.

In the absence of supporting evidence linking non-network–other capex to customer number growth, the AER does not consider it appropriate to apply a scale escalator in its determination of the non-network–other capex allowance.[652] Therefore, the AER does not accept SP AusNet's proposed application of a scale escalator to its non-network–other capex in the forthcoming regulatory control period.

However, the AER's draft decision was based on the average of the 2006–08 direct costs for this capex cost category and, therefore, it reflects historical 'growth' of non-network–other capex which exhibits a decreasing trend over the years 2004 to 2009. The AER notes that, across this period, SP AusNet leased motor vehicles in all years except 2008 when it purchased motor vehicles.[653] Therefore, the AER considers that, in determining the non-network–other capex direct costs in the forthcoming regulatory control period by applying the average of direct costs for 2005 to 2009 inclusive, SP AusNet would receive a 'growth escalator' despite its decreasing historical cost trend.

However, given that SP AusNet has stated the unwinding of its contractual arrangements with Tenix Alliance in the 2006–10 regulatory period means that it will have to incur capex previously accounted as opex, the AER expect that SP AusNet's non-network–capex to increase in the forthcoming regulatory control period. The AER notes that SP AusNet has forecast to increase its non-network–other capex in 2010. Therefore, AER considers it is appropriate to consider the years 2005 to 2010 inclusive (adjusted to remove motor vehicle purchases in 2008) in establishing the expenditure trend line used to determine SP AusNet's non-network–other capex direct costs in the forthcoming regulatory control period. This is because the inclusion of 2010 data in establishing the 'historical' expenditure trend captures any increasing costs and should reflect the expected increased capex. That said, the AER considers that the inclusion of SP AusNet's estimated 2010 capex in calculating the average direct cost to be allowed in the forthcoming regulatory control period will provide compensation consistent with its network growth.

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651 SP AusNet, *Response to information requested 9 September 2010*, 13 September 2010.

652 SP AusNet, *Response to information requested 9 September 2010*, 9 September 2010; SP AusNet, *Response to information requested 9 September 2010*, 13 September 2010.

653 SP AusNet, *Initial regulatory proposal*, p. 161.

The AER has also given consideration to SP AusNet's proposal to exclude a return of capital component and retain only the return on capital component for its non-network–other capex as a means to address its concern that it would be penalised if it overspent its non-network–other capex allowance as set out at chapter 9 (Opening asset base) of this final decision. In summary, the AER does not accept SP AusNet's proposal and will continue to apply both a return on and return of capital component to the non-network–other capex in the forthcoming regulatory control period.

Accordingly, the AER's final decision on SP AusNet's non-network–other capex direct costs is based on the historical expenditure trend for the years 2005 to 2009 inclusive. The AER considers that its final decision on the direct costs for the non-network–other capex category is for an amount that SP AusNet reasonably requires in the forthcoming regulatory control period.

Table P.111 sets out SP AusNet's revised non-network–other capex proposal and the AER's final decision.

Table P.111 Non-network—other capex—direct cost—SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet revised regulatory proposal	3.7	3.7	3.8	3.9	3.9	19.0
AER final decision	4.1	4.1	4.1	4.1	4.1	20.7

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes SP AusNet's proposed margins, overheads and real cost increases.
Source: SP AusNet, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.7.5.6 United Energy

Having noted that the AER had accepted its initial regulatory proposal United Energy stated it had reviewed its initial proposal, particularly its fleet requirements and proposed a 59.5 per cent increase to the $13.1 million ($2010) proposed in its initial regulatory proposal.[654] Given this increase, the AER requested United Energy to provide information supporting the requirement for the revised and significantly higher capex amount.

In response, United Energy stated that its initial regulatory proposal had not included costs for purchase of trucks and that it required to own and maintain a larger fleet because it was " bringing a significant amount of services back in house".[655] The AER notes that clause 6.10.3(b) of the NER states that a DNSP's revised regulatory proposal should be limited to matters where the AER has not accepted the DNSP's initial regulatory proposal. Therefore, although the AER accepted United Energy's initial regulatory proposal in respect of the direct costs of its non-network–other capex, the AER has considered United Energy's revised regulatory proposal on this

[654] United Energy, *Revised regulatory proposal*, p. 155; United Energy, *Revised regulatory proposal–RIN template 2.1*, August 2010; AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, p. 433.
[655] United Energy, *Response to information requested 9 September 2010*, 14 September 2010.

matter because the AER considers United Energy will require trucks in its fleet so as to be able to deliver its direct control services.

The AER requested and received a copy of United Energy's fleet asset management policy.[656] United Energy's fleet asset management policy states that its current fleet has 144 vehicles comprising elevating platform vehicles, heavy commercial vehicles, light commercial vehicles, passenger vehicles, trailers and forklifts.[657] United Energy has informed the AER that it will be purchasing/replacing 320 vehicles, ranging across all vehicle categories, in the forthcoming regulatory control period.[658] However, it did not provide any supporting documentation explaining and justifying its proposed increase in fleet expenditure and its proposed adjustments to expenditures on trucks and vehicles in the forthcoming regulatory control period.

Further, United Energy has stated its "[f]leet numbers are maintained at the optimum levels to meet the requirements of the UED related works".[659] On the basis of the information submitted by United Energy, the AER has not been able to confirm this statement. However, the AER recognises that non-network–other capex for trucks in the forthcoming regulatory control period. Therefore, the AER has not accepted United Energy's proposed non-network–other capex direct costs amount of $20.9 million ($2010). Instead the AER has substituted an amount of $17 million ($2010). This substituted amount as the average of the AER's draft decision and United Energy's revised regulatory proposal on the non-network–other capex direct costs.

Table P.112 sets out United Energy's revised non-network–other capex proposal and the AER's final decision.

Table P.112 Non-network—other capex—direct cost—United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy revised regulatory proposal	8.8	4.3	2.5	2.8	2.5	20.9
AER final decision	8.0	3.5	1.8	2.0	1.8	17.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes United Energy's proposed margins, overheads and real cost increases.
Source: United Energy, *Revised regulatory proposal–RIN template 2.1*, July 2010.

P.7.6 AER conclusion

This section P.7 has assessed the direct costs of the proposed allowance for non-network–other capex which is one component of each Victorian DNSP's proposed total forecast capital expenditure. The AER considers that the direct costs determined

656 United Energy, *Response to information requested 24 September 2010*, 8 October 2010.
657 United Energy, *Fleet Management Strategy: Document No: UE 4356-157*, 2 April 2009, p. 12.
658 United Energy, *Response to information requested 9 September 2010*, 14 September 2010.
659 United Energy, *United Energy Asset Management Plan 2009–2016*, Version 1.0 Final For Review, Undated, p. 196.

in this section P.7 are consistent with the requirement in clause 6.5.7(c) of the NER that the forecast capital expenditure reasonably reflects the capital expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each Victorian DNSP's total forecast capital expenditure.

That constituent decision, which should be read together with this appendix, is discussed at chapter 8.

Table P.113 sets out the AER's conclusion on the direct cost of each Victorian DNSP's revised regulatory proposals on non-network–other capex which it considers is consistent with forecast capital expenditure that reasonably reflects the capex criteria.

As explained at the beginning of this section P.7, in coming to this view, the AER has assessed the information submitted in support of each Victorian DNSP's revised regulatory proposals on non-network–other capex, having regard to the capex factors. Where relevant, the AER has made the minimum necessary change to the Victorian DNSPs' forecast non-network–other capex.

Table P.113 AER conclusion— Victorian DNSPs' 2011–15 non-network—other capex—direct cost ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	2.9	3.2	2.9	3.0	3.0	14.9
Powercor	14.6	15.6	14.7	14.9	14.7	74.5
JEN	3.4	16.1	3.4	3.5	4.0	30.5
SP AusNet	4.1	4.1	4.1	4.1	4.1	20.7
United Energy	8.0	3.5	1.8	2.0	1.8	17.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes margins, overheads and real cost increases.

Q Alternative control services prices and labour rates

Q.1 Public lighting services—proposed prices

The following tables provide each of the DNSPs proposed public lighting operation, maintenance and repair (OMR) charges for the 2011–15 regulatory control period.

Table Q.1 CitiPower—current and proposed public lighting charges ($, nominal)

	Current			Proposed		
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	43.33	65.82	68.23	68.25	69.12	70.13
Sodium high pressure 150 watt	79.64	100.71	104.39	105.35	107.31	109.25
Sodium high pressure 250 watt	80.85	102.36	106.11	107.03	108.98	110.93
T5 2x14 watt	30.35	38.19	39.32	40.49	41.70	42.73
Fluorescent 20 watt	86.23	130.98	135.77	135.81	137.55	139.57
Fluorescent 40 watt	86.66	131.64	136.45	136.49	138.24	140.27
Mercury vapour 50 watt	61.53	93.46	96.88	96.91	98.15	99.59
Mercury vapour 125 watt	68.46	103.99	107.80	107.83	109.21	110.81
Mercury vapour 250 watt	67.91	85.98	89.13	89.91	91.54	93.18
Mercury vapour 400 watt	68.72	87.01	90.19	90.98	92.63	94.29
Mercury vapour 700 watt	101.06	127.95	132.64	133.79	136.23	138.66
Sodium high pressure 70 watt	91.86	139.54	144.64	144.68	146.54	148.69
Sodium high pressure 100 watt	81.23	102.73	106.48	107.46	109.45	111.44
Sodium high pressure 220 watt	81.01	102.56	106.32	107.24	109.20	111.15
Sodium high pressure 360 watt	82.47	104.41	108.23	109.17	111.16	113.15
Sodium high pressure 400 watt	88.94	112.60	116.72	117.73	119.88	122.02
Sodium high pressure 1000 watt	160.08	202.67	210.10	211.92	215.78	219.64
Metal halide 70 watt	141.69	215.23	223.10	223.17	226.03	229.34
Metal halide 100 watt	125.03	158.12	163.90	165.41	168.47	171.53
Metal halide 150 watt	125.83	159.13	164.94	166.46	169.55	172.62
Metal halide 250 watt	97.02	122.83	127.33	128.44	130.78	133.12
Metal halide 400 watt	97.02	122.83	127.33	128.44	130.78	133.12
Metal halide 1000 watt	144.72	183.22	189.94	191.58	195.07	198.57

Source: CitiPower, *Regulatory Proposal 2011–15—public lighting model*, 30 November 2009 (updated in March 2010).

Table Q.2 Powercor—current and proposed public lighting charges ($, nominal)

	Current		Proposed			
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	34.56	42.74	45.14	48.49	47.11	46.86
Sodium high pressure 150 watt	68.31	75.26	78.82	83.47	83.31	84.06
Sodium high pressure 250 watt	69.67	77.17	80.90	85.80	85.47	86.16
T5 2x14 watt	28.52	33.49	34.44	35.45	36.33	37.04
Fluorescent 20 watt	96.08	118.81	125.48	134.79	130.98	130.26
Fluorescent 40 watt	96.08	118.81	125.48	134.79	130.98	130.26
Mercury vapour 50 watt	48.04	59.40	62.74	67.40	65.49	65.13
Mercury vapour 125 watt	46.66	57.69	60.93	65.46	63.60	63.25
Mercury vapour 250 watt	52.95	58.65	61.48	65.21	64.96	65.48
Mercury vapour 400 watt	61.31	67.91	71.19	75.51	75.21	75.82
Mercury vapour 700 watt	92.66	102.63	107.60	114.12	113.67	114.59
Sodium low pressure 90 watt	92.22	101.60	106.41	112.68	112.46	113.48
Sodium low pressure 180 watt	92.22	101.60	106.41	112.68	112.46	113.48
Sodium high pressure 400 watt	92.66	102.63	107.60	114.12	113.67	114.59
Incandescent 100 watt	96.08	118.81	125.48	134.79	130.98	130.26
Incandescent 150 watt	96.08	118.81	125.48	134.79	130.98	130.26
Metal halide 250 watt	92.66	102.63	107.60	114.12	113.67	114.59
Metal halide 400 watt	92.66	102.63	107.60	114.12	113.67	114.59

Source: Powercor, *Regulatory Proposal 2011–15—public lighting model*, 30 November 2009 (updated in March 2010).

Table Q.3 Jemena Electricity Networks (JEN)—current and proposed public lighting charges ($, nominal)

	Current		Proposed			
Lighting Service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	32.02	37.34	40.55	42.59	44.78	47.40
Sodium high pressure 150 watt	61.97	72.54	77.37	80.91	84.64	88.86
Sodium high pressure 250 watt	64.17	74.35	79.36	83.01	86.85	91.22
T5 2x14 watt	26.07	26.96	28.21	29.34	30.55	31.86
Fluorescent 20 watt	40.03	46.67	50.69	53.23	55.98	59.25
Fluorescent 40 watt	40.03	46.67	50.69	53.23	55.98	59.25
Fluorescent 80 watt	40.03	46.67	50.69	53.23	55.98	59.25
Mercury vapour 50 watt	40.03	46.67	50.69	53.23	55.98	59.25
Mercury vapour 125 watt	47.07	54.88	59.61	62.60	65.83	69.68
Mercury vapour 250 watt	61.60	71.38	76.18	79.69	83.38	87.57
Mercury vapour 400 watt	69.30	80.30	85.70	89.65	93.80	98.51
Sodium Low Pressure 90 watt	77.46	90.68	96.71	101.14	105.80	111.07
Sodium high pressure 50 watt	65.69	76.89	82.01	85.77	89.72	94.19
Sodium high pressure 100 watt	84.90	99.38	105.99	110.85	115.95	121.74
Sodium high pressure 400 watt	85.35	98.88	105.54	110.41	115.52	121.32
Sodium high pressure 250 watt (24 hrs)	100.11	115.99	123.80	129.50	135.49	142.30
Metal halide 70 watt	82.29	95.95	104.21	109.45	115.09	121.82
Metal halide 100 watt	137.57	161.04	171.75	179.63	187.90	197.26
Metal halide 150 watt	137.57	161.04	171.75	179.63	187.90	197.26
Metal halide 250 watt	137.97	159.85	170.62	178.48	186.74	196.11
Incandescent 55 watt	40.03	46.67	50.69	53.23	55.98	59.25
Incandescent 100 watt	49.95	58.24	63.26	66.44	69.86	73.94
Incandescent 150 watt	62.44	72.81	79.07	83.05	87.32	92.43

Source: JEN Electricity Networks, *Regulatory Proposal 2011–15—public lighting model*, 30 November 2009 (updated in March 2010). JEN's submission had prices including GST but the prices in the above table are excluding GST.

Table Q.4 SP AusNet—current and proposed public lighting charges ($, nominal)—central region

	Current		Proposed			
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	30.78	38.28	41.14	43.82	46.46	49.14
Sodium high pressure 150 watt	57.01	84.04	88.86	93.80	98.65	103.55
Sodium high pressure 250 watt	57.07	86.30	91.22	96.26	101.20	106.20
T5 2x14 watt	28.74	43.62	46.19	47.53	49.63	50.90
T5 2x24 watt	30.90	48.00	50.80	52.24	54.48	55.78
Mercury vapour 50 watt	47.09	58.56	62.94	67.05	71.09	75.18
Mercury vapour 125 watt	45.25	56.27	60.47	64.42	68.30	72.23
Mercury vapour 250 watt	59.92	89.32	94.46	99.71	104.86	110.07
Mercury vapour 400 watt	62.21	92.73	98.06	103.51	108.85	114.27
Sodium high pressure 50 watt[a]	29.57	43.70	46.21	48.78	51.30	53.85
Sodium high pressure 100 watt	61.00	89.92	95.09	100.37	105.55	110.80
Sodium high pressure 400 watt	81.04	120.80	127.74	134.85	141.81	148.86

(a) While SP AusNet had included a 2010 charge for the Sodium High Pressure 50W light in its model, no such charge has been approved by the AER. This light has not been considered by the AER in this draft decision. However, the AER will consider all submissions to its draft decision on this lighting service, when making its final determination.

Source: SP AusNet, *Revised regulatory proposal 2011–2015—public lighting model*, July 2010 (updated in September 2010).

Table Q.5 SP AusNet—current and proposed public lighting charges ($, nominal)—north and east regions

	Current	Proposed				
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	33.53	44.56	47.76	50.80	53.76	56.76
Sodium high pressure 150 watt	66.32	95.04	100.41	105.96	111.40	116.90
Sodium high pressure 250 watt	68.38	95.52	100.89	106.44	111.87	117.37
T5 2x14 watt	31.48	49.62	52.38	53.93	56.25	57.73
T5 2x24 watt	33.69	54.06	57.05	58.70	61.16	62.69
Mercury vapour 50 watt	49.62	65.95	70.68	75.19	79.57	84.00
Mercury vapour 125 watt	49.62	65.95	70.68	75.19	79.57	84.00
Mercury vapour 250 watt	71.12	98.02	103.57	109.31	114.92	120.60
Mercury vapour 400 watt	73.17	100.85	106.56	112.47	118.24	124.08
Sodium high pressure 50 watt[a]	32.22	49.42	52.21	55.10	57.93	60.79
Sodium high pressure 100 watt	70.96	101.70	107.44	113.38	119.19	125.08
Sodium high pressure 400 watt	97.10	133.84	141.42	149.26	156.91	164.67

(a) While SP AusNet had included a 2010 charge for the Sodium High Pressure 50W light in its model, no such charge has been approved by the AER. This light has not been considered by the AER in this draft decision. However, the AER will consider all submissions to its draft decision on this lighting service, when making its final determination.

Source: SP AusNet, *Revised regulatory proposal 2011–2015—public lighting model*, July 2010 (updated in September 2010).

Table Q.6 United Energy—current and proposed public lighting charges ($, nominal)

	Current		Proposed			
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	37.47	49.13	52.51	56.12	59.71	63.17
Sodium high pressure 150 watt	60.94	78.81	82.91	87.27	91.62	95.87
Sodium high pressure 250 watt	61.38	80.12	84.37	88.87	93.36	97.73
T5 2x14 watt	26.56	25.34	25.97	26.73	27.74	28.71
Fluorescent 2x20 watt	48.34	63.38	67.74	72.40	77.03	81.48
Fluorescent 3x20 watt	48.34	63.38	67.74	72.40	77.03	81.48
Mercury vapour 50 watt	55.46	72.72	77.72	83.06	88.38	93.49
Mercury vapour 125 watt	55.46	72.72	77.72	83.06	88.38	93.49
Mercury vapour 250 watt	55.86	72.91	76.77	80.87	84.96	88.93
Mercury vapour 400 watt	77.34	100.95	106.30	111.97	117.63	123.14
Mercury vapour 700 watt	77.34	100.95	106.30	111.97	117.63	123.14
Sodium high pressure 70 watt	82.06	107.60	115.00	122.91	130.77	138.33
Sodium high pressure 100 watt	67.03	86.69	91.20	95.99	100.79	105.45
Sodium high pressure 400 watt	77.34	100.95	106.30	111.97	117.63	123.14
Metal halide 70 watt	82.27	106.39	111.93	117.81	123.69	129.42
Metal halide 100 watt	82.27	106.39	111.93	117.81	123.69	129.42
Metal halide 150 watt	82.27	106.39	111.93	117.81	123.69	129.42
Metal halide 250 watt	82.86	108.17	113.90	119.97	126.03	131.93
Metal halide 400 watt	82.86	108.17	113.90	119.97	126.03	131.93

Source: United Energy, *Regulatory Proposal 2011–2015—public lighting model*, 30 November 2009.

Q.2 Fee based alternative control services

Following the considerations set out in chapter 20, the following tables set out the draft decision, revised proposal and AER final decision prices for the DNSPs' fee based alternative control services for 2011 (in $2010). The tables also present the overall percentage difference between the DNSPs' revised proposed prices and the AER's final determination prices. All prices are GST exclusive.

Table Q.7 AER final decision for CitiPower—fee based alternative control services prices for 2011 ($, 2010)

Fee based services	Draft decision price	Revised proposal price	AER final decision price	Difference between proposed price and AER price (per cent)
Meter Accuracy Test—single phase—BH	154.23	361.17	308.10	–15%
Meter Accuracy Test—single phase—AH	184.42	393.62	337.72	–14%
Meter Accuracy Test—Single phase, each additional meter—BH	41.77	143.99	137.57	–4%
Meter Accuracy Test—multi phase—BH	170.33	460.56	403.13	–12%
Meter Accuracy Test—multi phase—AH	204.54	502.91	443.00	–12%
Meter Accuracy Test—Multi phase additional meter—BH	57.87	247.88	236.89	–4%
Meter Accuracy Test—CT—BH	218.63	450.83	393.82	–13%
Meter Accuracy Test—CT—AH	264.91	492.21	432.69	–12%
Meter Investigation Test—BH	152.11	287.74	237.90	–17%
Meter Investigation Test—AH	181.76	312.88	259.95	–17%
Reconnections (incl. Customer Transfer)—BH	12.55	13.27	12.55	–5%
Reconnections (same day)—BH	15.73	16.63	15.73	–5%
Reconnections (incl. Customer Transfer)—AH	53.57	56.62	53.57	–5%
Disconnection (includes DNP)—BH	12.72	13.45	12.72	–5%
Special reading / Customer Transfers—BH	9.22	10.29	9.73	–5%
Service Truck Visit—BH	246.04	462.37	357.84	–23%
Service Truck Visit—AH	300.38	504.40	393.40	–22%
Wasted Truck Visit—BH	115.73	320.44	225.91	–29%
Wasted Truck Visit—AH	139.88	350.34	248.92	–29%
Solar PV Conn—Single phase—BH (unit cost)	173.26	215.99	217.49	–1%
Solar PV Conn—Single phase—AH (unit cost)	198.07	230.13	232.97	–1%

Routine New Connections—DNSP Responsible for metering, customers<100amps				
AMI Single phase—BH	314.87	459.20	357.66	–22%
AMI Single phase—AH	357.13	489.58	381.16	–22%
AMI Multi phase DC—BH	398.89	548.00	441.67	–19%
AMI Multi phase DC—AH	441.15	578.38	465.18	–20%
AMI Multi phase CT—BH	1 476.44	2,052.57	1,932.16	–6%
AMI Multi phase CT—AH	1 746.77	2,215.43	2,100.76	–5%
Routine New Connections—DNSP Not Responsible for metering, customers<100amps				
AMI Single phase—BH	257.22	401.54	300.01	–25%
AMI Single phase—AH	299.48	431.93	323.51	–25%
AMI Multi phase DC—BH	341.24	490.35	384.02	–22%
AMI Multi phase DC—AH	383.50	520.73	407.53	–22%
AMI Multi phase CT—BH	1 418.79	1,994.92	1,874.51	–6%
AMI Multi phase CT—AH	1 689.12	2,157.78	2,043.11	–5%
Miscellaneous fee based services				
Reserve feeder—sub-transmission ($/kVA)	Further information requested	1.43	1.43	–0%
Reserve feeder—high voltage ($/kVA)	Further information requested	2.95	2.95	–0%
Reserve feeder—low voltage ($/kVA)	Further information requested	7.29	7.29	–0%
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh—BH	Further information requested	355.23	302.65	–15%
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh—AH	Further information requested	389.34	333.99	–14%
Fault level compliance	Further information requested	Service not being provided	–	–

AER final decision for Powercor—fee based alternative control services prices for 2011 ($, 2010)

Fee based services	Draft decision price	Revised proposal price	AER final decision price	Difference between proposed price and AER price (per cent)
Meter Accuracy Test—single phase—BH	152.48	342.45	315.24	–8%
Meter Accuracy Test—single phase—AH	182.66	373.22	345.94	–7%
Meter Accuracy Test—Single phase additional meter—BH	41.27	139.94	128.70	–8%
Meter Accuracy Test—multi phase—BH	168.58	438.83	403.70	–8%
Meter Accuracy Test—multi phase—AH	202.79	479.20	443.98	–7%
Meter Accuracy Test—Multi phase additional meter—BH	57.36	236.72	217.52	–8%
Meter Accuracy Test—CT—BH	216.87	430.14	395.72	–8%
Meter Accuracy Test—CT—AH	263.16	469.64	435.14	–7%
Meter Investigation Test—BH	148.79	271.34	249.98	–8%
Meter Investigation Test—AH	178.06	295.03	273.62	–7%
Reconnections (incl Customer Transfer)—BH	17.70	18.71	17.70	–5%
Reconnections (same day)—BH	27.98	29.58	27.98	–5%
Reconnections (incl Customer Transfer)—AH	73.48	77.67	73.48	–5%
Disconnection (includes DNP)—BH	18.73	19.80	18.73	–5%
Special reading / Customer Transfers—BH	14.37	15.70	14.86	–5%
Service Truck Visit—BH	248.05	454.52	391.68	–14%
Service Truck Visit—AH	304.40	447.90	435.43	–3%
Wasted Truck Visit—BH	114.73	238.12	209.39	–12%
Wasted Truck Visit—AH	138.88	259.93	231.26	–11%
Solar PV Conn—Single phase—BH (unit cost)	167.87	204.76	200.84	–2%

Solar PV Conn—Single phase—AH (unit cost)	191.34	217.79	214.59	–1%
New Connections—DNSP Responsible for metering, customers<100amps				
AMI Single phase—BH	278.05	364.08	326.29	–10%
AMI Single phase—AH	320.31	388.87	351.03	–10%
AMI Multi phase DC—BH	377.74	469.46	425.99	–9%
AMI Multi phase DC—AH	420.00	494.25	450.72	–9%
AMI Multi phase CT—BH	1 432.50	1,950.30	1761.09	–10%
AMI Multi phase CT—AH	1 695.12	2,104.35	1914.80	–9%
Routine New Connections—DNSP Not Responsible for metering, customers<100amps				
AMI Single phase—BH	220.39	306.43	268.64	–12%
AMI Single phase—AH	262.65	331.22	293.38	–11%
AMI Multi phase DC—BH	320.09	411.81	368.34	–11%
AMI Multi phase DC—AH	362.35	436.59	393.07	–10%
AMI Multi phase CT—BH	1 374.85	1,892.65	1703.44	–10%
AMI Multi phase CT—AH	1 637.46	2,046.70	1857.15	–9%
Miscellaneous fee based services				
Reserve feeder—sub-transmission ($/kVA)	Further information requested	0.78	0.78	0%
Reserve feeder—high voltage ($/kVA)	Further information requested	3.99	3.99	0%
Reserve feeder—low voltage ($/kVA)	Further information requested	14.11	14.11	0%
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh—BH	Further information requested	337.65	310.24	–7%
Re-test of type 5 & 6 metering installations for first tier customers with annual consumption greater than 160MWh—AH	Further information requested	370.08	342.59	–8%

Table Q.8 AER final decision for JEN— fee based alternative control services prices for 2011 ($, 2010)

Fee based services	Draft decision price	Revised proposal price	AER final decision price	Difference between proposed price and AER price (per cent)
Manual—energisation of new premises—BH	10.10	12.00	11.74	–2%
Manual—energisation of new premises—AH	34.34	36.97	35.41	–4%
Manual—re-energisation Existing Premises—BH	10.10	12.00	11.74	–2%
Manual—re-energisation Existing Premises—AH	34.34	36.97	35.41	–4%
Manual de-energisation—Existing Premises—BH	16.53	20.14	20.06	0%
Manual de-energisation—Existing Premises—AH	37.46	41.75	40.56	–3%
Connection—temporary supply (overhead supply—coincident abolishment)—BH	239.24	368.00	420.11	14%
Connection—temporary supply (overhead supply—coincident abolishment)—AH	268.09	429.24	466.47	9%
Temporary disconnect—reconnect for non-payment—BH	28.40	29.35	28.77	–2%
Temporary disconnect—reconnect for non-payment—AH	40.43	41.74	40.53	–3%
Adjust time switch—BH only	10.02	10.38	10.83	4%
Manual special meter reads—BH only	6.59	8.15	8.67	6%
Service vehicle visit—BH	222.46	231.41	306.12	32%
Service vehicle visit—AH	330.63	344.72	337.25	–2%
Wasted service truck visit—not DNSP fault—BH	149.33	154.41	305.64	98%
Wasted service truck visit—not DNSP fault—AH	173.84	179.93	346.17	92%
Fault response—not DNSP fault—BH	242.32	252.29	258.13	2%

Fault response—not DNSP fault—AH	283.99	295.68	288.94	–2%
Retest of types 5 and 6 metering installations for first tier customers <160MWh—BH	237.22	241.32	233.23	–3%
Retest of types 5 and 6 metering installations for first tier customers <160MWh—AH	300.77	305.81	294.42	–4%
Retest of types 5 and 6 metering installations for first tier customers > 160MWh—BH	Further information requested	241.32	233.23	–3%
Retest of types 5 and 6 metering installations for first tier customers > 160MWh—AH	Further information requested	305.81	294.42	–4%
Reserve feeder ($/kW)	Further information requested	17.57	4.32	75%
Routine new connections where JEN is responsible for metering, customers<100amps				
Routine Connection—Single Phase service connection to new premises—BH	338.39	349.35	397.11	14%
Routine Connection—Single Phase service connection to new premises—AH	399.23	417.05	455.10	9%
Routine Connection—Three phase service connection to new premises with direct connected metering—BH	425.85	435.19	487.33	12%
Routine Connection—Three phase service connection to new premises with direct connected metering—AH	483.34	502.89	545.26	8%
Routine new connections where JEN is NOT responsible for metering, customers<100amps				
Routine Connection—Single Phase service connection to new premises—BH	Further information requested	349.35	397.11	14%
Routine Connection—Single Phase service connection to new premises—AH	Further information requested	417.05	455.10	9%
Routine Connection—Three phase service connection to new premises with direct connected metering—BH	Further information requested	435.19	487.33	12%

Routine Connection—Three phase service connection to new premises with direct connected metering—AH	Further information requested	502.89	545.26	8%

Note: While JEN disagreed with the AER's draft decision labour rates and times for alternative control services, JEN's revised proposal prices incorporated the AER's draft decision labour rates and times for services, which have been revised upwards in the final decision. Accordingly, many of the final decision prices appear as an increase on JEN's revised proposed prices.
JEN's build up model proposed prices in 2008 dollars. The AER has used JEN's Forecast Data Model submitted as part of its revised regulatory proposal to adjust the prices from 2008 dollars to 2010 dollars.

Table Q.9 AER final decision for SP AusNet—fee based alternative control services prices for 2011 ($, 2010)

Fee based services	Draft decision price	Revised proposal price	AER final decision price	Difference between proposed price and AER price (per cent)
Field officer visits				
Field officer visits—BH	15.12	15.68	15.18	–3%
Field officer visits—AH	105.86	109.81	106.32	–3%
Routine new connections—SP AusNet responsible for metering, customers<100amps				
Single Ø Overhead—BH	190.28	197.12	191.23	–3%
Single Ø Overhead—AH	262.01	271.85	263.37	–3%
Single Ø Underground—BH	153.55	159.97	154.44	–3%
Single Ø Underground—AH	210.71	219.52	211.93	–3%
Multi Ø Overhead—Direct Connected Meter—BH	266.20	275.24	267.45	–3%
Multi Ø Overhead—Direct Connected Meter—AH	355.87	368.66	357.64	–3%
Multi Ø Overhead—CT Connected Meter—BH	324.48	335.96	326.07	–3%
Multi Ø Overhead—CT Connected Meter—AH	324.48	521.07	478.26	–8%
Multi Ø Underground—Direct Connected Meter—BH	197.26	205.51	198.41	–3%
Multi Ø Underground—Direct Connected Meter—AH	266.75	277.9	268.30	–3%
Multi Ø Underground—CT Connected Meter—BH	274.60	286.08	276.19	–3%
Multi Ø Underground—CT Connected Meter—AH	425.91	443.71	428.38	–3%
Overhead Supply—Coincident Disconnection (Truck visit)—BH	353.92	367.6	355.81	–3%
Overhead Supply—Coincident Disconnection (Truck visit)—AH	538.99	570.15	466.47	–18%

Routine new connections—SP AusNet not responsible for metering, customers<100amps				
Single Ø Overhead—BH	Further information requested	197.12	191.23	–3%
Single Ø Overhead—AH	Further information requested	271.85	263.37	–3%
Single Ø Underground—BH	Further information requested	159.97	154.44	–3%
Single Ø Underground—AH	Further information requested	219.52	211.93	–3%
Multi Ø Overhead—Direct Connected Meter—BH	Further information requested	275.24	267.45	–3%
Multi Ø Overhead—Direct Connected Meter—AH	Further information requested	368.66	357.64	–3%
Multi Ø Overhead—CT Connected Meter—BH	Further information requested	335.96	326.07	–3%
Multi Ø Overhead—CT Connected Meter—AH	Further information requested	521.07	478.26	–8%
Multi Ø Underground—Direct Connected Meter—BH	Further information requested	205.51	198.41	–3%
Multi Ø Underground—Direct Connected Meter—AH	Further information requested	277.9	268.30	–3%
Multi Ø Underground—CT Connected Meter—BH	Further information requested	286.08	276.19	–3%
Multi Ø Underground—CT Connected Meter—AH	Further information requested	443.71	428.38	–3%
Overhead Supply—Coincident Disconnection (Truck visit)—BH	Further information requested	367.6	355.81	–3%

Overhead Supply—Coincident Disconnection (Truck visit)—AH	Further information requested	570.15	466.47	–18%
Service truck visits				
Service Truck Visit—BH	230.83	235.85	232.87	–1%
Wasted Truck Visit—BH	116.97	119.51	118.01	–1%
Service Truck Visit—AH	303.98	310.58	306.67	–1%
Truck Appointment—AH	Further information requested	923.69	Quoted service	–
Meter equipment tests				
Single phase	144.59	144.59	144.59	0%
Single phase (each additional meter)	49.86	49.86	49.86	0%
Multi Phase	194.45	194.45	194.45	0%
Multi Phase (each additional meter)	64.82	64.82	64.82	0%

Table Q.10 AER final decision for United Energy—fee based alternative control services prices for 2011 ($, 2010)

Fee based services	Draft decision price	Revised proposal price	AER final decision price	Difference between proposed price and AER price (per cent)
Field Officer Visits – Existing Premises				
Special read (basic meter)	9.97	9.97	9.97	0%
Special read (interval meter)	11.07	11.07	11.07	0%
Re-energise (fuse insert)—BH (unit rate)	35.91	35.91	35.91	0%
De-energise (fuse removal)—BH (unit rate)	35.91	35.91	35.91	0%
Express move in re-energise (fuse insert)—BH (unit rate)	108.21	108.21	108.21	0%
Re-energise (fuse insert)—AH (unit rate)	114.77	114.77	114.77	0%
De-energise (fuse removal)—AH (unit rate)	114.77	114.77	114.77	0%
Express move in re-energise (fuse insert)—AH (unit rate)	114.77	114.77	114.77	0%
Temporary Supplies (exc inspection) – Coincident Disconnection				
Standard single phase—BH (unit rate)	83.97	83.97	83.97	0%
Multi phase to 100A—BH (unit rate)	83.97	83.97	83.97	0%
Standard single phase—AH (unit rate)	176.96	176.96	176.96	0%
Multi phase to 100A—AH (unit rate)	176.96	317.90	317.90	0%
Temporary Supplies (exc inspection) – Independent Disconnection				
Independent disconnection standard single phase—BH (unit rate)	167.93	167.93	167.93	0%
Independent disconnection multi phase to 100A—BH (unit rate)	158.32	333.66	333.66	0%
Independent disconnection standard single phase—AH (unit rate)	353.91	353.91	353.91	0%
Independent disconnection multi phase to 100A—AH (unit rate)	845.41	845.41	845.41	0%

Conversion from Coincidental to Independent Disconnection				
Standard single phase – changed from coincidental to independent (unit rate)	83.96	83.96	83.96	0%
Multi Phase – changed from coincidental to independent (unit rate)	176.96	176.96	176.96	0%
New Connection where United Energy is the Responsible Person				
Single phase single element—BH (unit rate)	201.38	201.38	201.38	0%
Single phase two element (off-peak)—BH (unit rate)	201.38	201.38	201.38	0%
Three phase direct connected—BH (unit rate)	201.38	201.38	201.38	0%
Single phase single element—AH (unit rate)	226.08	261.35	261.35	0%
Single phase two element (off-peak)—AH (unit rate)	98.24	317.19	317.19	0%
Three phase direct connected—AH (unit rate)	329.50	358.21	358.21	0%
Routine new connections—three phase current transformer connected—BH	Further information requested	967.47	Quoted	–
Routine new connections—three phase current transformer connected—AH	Further information requested	1038.59	Quoted	–
New Connections – where United Energy is Not the Responsible Person				
Single phase single element—BH (unit rate)	87.51	87.51	87.51	0%
Single phase two element (off-peak)—BH (unit rate)	87.51	87.51	87.51	0%
Three phase direct connected—BH (unit rate)	87.51	87.51	87.51	0%
Single phase single element—AH (unit rate)	98.24	249.56	249.56	0%
Single phase two element (off-peak)—AH (unit rate)	98.24	325.19	325.19	0%
Three phase direct connected—AH (unit rate)	143.19	367.21	367.21	0%

Routine new connections—three phase current transformer connected—BH	Further information requested	953.66	Quoted	–
Routine new connections—three phase current transformer connected—AH	Further information requested	Not provided	Quoted	–
Service Vehicle Visits (without inspection)				
Service truck – first 30 minutes—BH (unit rate)	102.16	102.16	102.16	0%
Each additional 15 minutes—BH (unit rate)	41.98	41.98	41.98	0%
Wasted service truck visit—BH (unit rate)	41.98	41.98	41.98	0%
Service truck – first 30 minutes—AH (unit rate)	113.54	208.44	208.44	0%
Each additional 15 minutes—AH (unit rate)	44.95	44.95	44.95	0%
Wasted service truck visit—AH (unit rate)	47.67	103.95	103.95	0%
Meter Equipment Test				
Single phase	49.83	49.83	49.83	0%
Single phase (each additional meter)	44.29	44.29	44.29	0%
Multi phase	77.51	77.51	77.51	0%
Multi phase (each additional meter)	71.97	71.97	71.97	0%

Q.3 Quoted alternative control services labour rates

The following tables set out the proposed and AER approved labour charge out rates for application within each DNSP's quoted alternative control services in 2011. The tables also present the overall difference between revised proposal and AER final determination labour charge out rates. These tables are based on the considerations set out in chapter 20.

The AER notes that the labour charge out rates include all applicable overheads and a profit margin, as discussed in chapter 20. The labour rates for CitiPower, Powercor and United Energy also incorporate the cost of a vehicle, as stated.

Table Q.11 AER final decision for CitiPower—quoted alternative control services charge out rates for 2011 ($, 2010)

Quoted services	AER draft decision $/hour rate	Revised proposed $/hour rate (not including a vehicle)	AER final decision $/hour rate (including a vehicle)	Difference between proposed rate and AER rate (per cent)
General line worker (including a vehicle)—BH	79.80	115.14	116.36	1%
General line worker (including a vehicle)—AH	99.75	126.61	128.91	2%
Design/survey (including a vehicle)—BH	n/a	123.56	110.68	–10%
Design/survey (including a vehicle)—AH	n/a	139.16	130.36	–6%
Administration	n/a	47.85	47.85	0%

Table Q.12 AER final decision for Powercor—quoted alternative control services charge out rates for 2011 ($, 2010)

Quoted services	AER draft decision $/hour rate	Revised proposed $/hour rate (not including a vehicle)	AER final decision $/hour rate (including a vehicle)	Difference between proposed rate and AER rate (per cent)
General line worker (including a vehicle)—BH	79.80	112.11	108.76	–3%
General line worker (including a vehicle)—AH	99.75	123.28	120.54	–2%
Design/survey (including a vehicle)—BH	n/a	120.31	103.45	–14%
Design/survey (including a vehicle)—AH	n/a	135.50	121.89	–10%
Administration	n/a	45.34	45.34	0%

Table Q.13 AER final decision for JEN—quoted alternative control services charge out rates for 2011 ($, 2010)

Quoted services	AER draft decision $/hour rate	Revised proposed $/hour rate	AER final decision $/hour rate	Difference between proposed rate and AER rate (per cent)
Unit rate per man hour—BH	79.80	81.82	81.82	0%
Unit rate per man hour—AH	99.75	101.28	101.28	0%

Table Q.14 AER final decision for SP AusNet—quoted alternative control services charge out rates for 2011 ($, 2010)

	Labour category	Service description	SP AusNet proposed and AER final determination $/hour rate - BH	SP AusNet proposed and AER final determination $/hour rate - AH
1	Labour—wages	Construction Overhead Install	76.33	95.41
2	Labour—wages	Construction Underground Install	77.14	96.43
3	Labour—wages	Construction Substation Install	77.14	96.43
4	Labour—wages	Electrical Tester Including Vehicle & Equipment	113.04	141.30
5	Labour—wages	Construction	76.33	95.41
6	Labour—wages	Planner Including Vehicle	104.30	130.38
7	Labour—wages	Supervisor Including Vehicle	104.30	130.38
8	Labour—design	Design	81.01	101.26
9	Labour—design	Drafting	63.79	79.74
10	Labour—design	Survey	75.95	94.94
11	Labour—design	Tech Officer	75.95	94.94
12	Labour—design	Line Inspector	63.79	79.74
13	Labour—design	Contract Supervision	75.95	94.94
14	Labour—design	Protection Engineer	81.01	101.26
15	Labour—design	Maintenance Planner	75.95	94.94

Note: SP AusNet's regulatory proposal approaches quoted services in a similar manner to the other DNSPs—man-hours of labour plus materials to be charged at cost. The categories of labour and the charge-out rates proposed by

SP AusNet were submitted in an appendix to its initial regulatory proposal. The AER's and its consultant's analysis indicates that items 1, 2, 3 and 5 are services which are delivered using general line workers; items 4, 6 and 7 involve line worker level labour, but also include vehicle and item 6 includes equipment cost; items 8 to 15 cover design services provided by drafting officers, technical officers or engineers.

Table Q.15 AER final decision for United Energy—quoted alternative control services charge out rates for 2011 ($, 2010)

Description	Proposed 2011 rate
Hourly labour rate—one person, business hours	79.80
Hourly labour rate—one person plus vehicle, business hours	108.90
Hourly labour rate—one person, after hours	99.75
Hourly labour rate—one person plus vehicle, after hours	121.56

Source: United Energy, *Revised regulatory proposal*, p. 344.

Q.4 X factors for alternative control services

Q.4.1 Fee based alternative control services

The following tables set out the AER's final decisions on the X factors to apply to the CitiPower's, Powercor's and JEN's fee based alternative control services prices for 2012–15. The X factors approved for SP AusNet's and United Energy's fee based alternative control services are 1 per cent and zero, respectively.

Table Q.16 AER final decision for CitiPower and Powercor—approved X factors for fee based alternative control services (per cent)

	2012	2013	2014	2015
CitiPower—fee based 'connection' services - including reconnection, disconnection, and special reads services	–37.38	–27.19	–0.29	–0.22
CitiPower—other fee based services	–0.54	–1.79	–3.31	–1.81
Powercor—fee based 'connection' services - including reconnection, disconnection, and special reads services	–41.59	–29.36	–0.18	–0.14
Powercor—other fee based services	–1.24	–1.81	–2.67	–1.00

Source: CitiPower and Powercor, *Response to AER information request of 12 October 2010*, 15 October 2010.

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.

Table Q.17 AER final decision for JEN—approved X factors for fee based alternative control services (per cent)

	2012	2013	2014	2015
Business hours				
New Connection Services				
Connection—single phase service connection to new premises	–1.18	–1.47	–2.02	–1.35
Connection—three phase service connection to new premises with direct metering	–0.89	–1.12	–1.52	–1.02
Network Services				
Manual energisation of new premises	–1.86	–2.38	–3.16	–2.11
Manual re-energisation of existing premises	–1.86	–2.38	–3.16	–2.11
Manual de-energisation of existing premises	–1.88	–2.38	–3.18	–2.12
Temporary overhead supply— coincident abolishment	–1.47	–1.78	–2.49	–1.66
Temporary disconnect—reconnect for non-payment	–1.87	–2.38	–3.17	–2.11
Adjust time switch	–1.92	–2.38	–3.24	–2.15
Manual special meter reads	–1.87	–2.38	–3.16	–2.11
Service vehicle visit	–1.70	–2.04	–2.86	–1.90
Wasted service truck visit—not DNSP fault	–1.55	–1.88	–2.63	–1.75
Fault response—not DNSP fault	–1.72	–2.07	–2.90	–1.92
Meter test—single and multi phase meter installations with annual consumption of <160 MWh	–1.85	–2.38	–3.15	–2.10
Meter test—types 5 & 6 meter installation for first tier customers with annual consumption >160 MWh	–1.85	–2.38	–3.15	–2.10
After hours				
New connection services				
Connection—single phase service connection to new premises	–1.30	–1.61	–2.22	–1.48
Connection—three phase service connection to new premises with direct metering	–1.02	–1.29	–1.75	–1.18
Network Services				

Manual energisation of new premises	–1.85	–2.38	–3.14	–2.10
Manual re-energisation of existing premises	–1.85	–2.38	–3.14	–2.10
Manual de-energisation of existing premises	–1.86	–2.38	–3.15	–2.11
Temporary overhead supply—coincident abolishment	–1.54	–1.86	–2.61	–1.73
Temporary disconnect—reconnect for non-payment	–1.86	–2.38	–3.15	–2.11
Service vehicle visit	–1.79	–2.16	–3.01	–2.00
Wasted service truck visit—not DNSP fault	–1.61	–1.95	–2.73	–1.81
Fault response—not DNSP fault	–1.76	–2.12	–2.96	–1.96
Meter test—single and multi phase meter installations with annual consumption of <160 MWh	–1.85	–2.38	–3.14	–2.10
Meter test—types 5 & 6 meter installation for first tier customers with annual consumption >160 MWh	–1.85	–2.38	–3.14	–2.10

Note: X factors for new connections services where JEN is responsible for metering are identical to those where JEN is not responsible for metering.

Source: JEN, *Response to AER information request of 12 October 2010,* 18 October 2010.

Q.4.2 Quoted alternative control services

The following tables set out the AER's final decisions on the X factors to apply to the CitiPower's, Powercor's and JEN's quoted alternative control services labour charge out rates for 2012–15.

The AER's final decision is that SP AusNet's and United Energy's quoted alternative control services will be escalated by the respective AER approved outsourced labour escalators for standard control services, set out in table 20.15 and 20.24 of the final decision.

Table Q.18 AER final decision—CitiPower's and Powercor's X factors for quoted alternative control services labour rates (per cent)

	2012	2013	2014	2015
X (per cent)	–3.02	–2.22	–0.67	–1.40

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.

Source: CitiPower and Powercor, *Response to AER information request of 12 October 2010*, 15 October 2010.

Table Q.19 AER final decision—JEN's X factors for quoted alternative control services labour rates (per cent)

	2012	2013	2014	2015
X (per cent)	–1.98	–2.38	–3.33	–2.20

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.

Source: JEN, *Response to AER information request of 12 October 2010,* 18 October 2010.