Jemena Electricity Networks (Vic) Ltd

Revised regulatory proposal

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Overview

JEN supplies electricity to over 305,000 customers of which about 91 per cent are residences. JEN's customers cover a 950 km^2 area of Melbourne's city and north-western suburbs, with Tullamarine International Airport at the approximate centre.

The network service area ranges from Couangalt, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

JEN has responded to its regulatory incentives and, as a result, JEN's network is in good shape and JEN is highly efficient compared to its peers. Its service reliability levels are excellent and its investment plans for the future are carefully designed to meet the emerging challenges of increasing peak demand, public and workplace safety, and aging infrastructure at just the right time to maintain our network's performance.

This revised regulatory proposal is designed to enable JEN to deliver for its customers.

On 30 November 2009 Jemena Electricity Networks (Vic) Ltd (**JEN**) submitted to the Australian Energy Regulator (**AER**) its original regulatory proposal for the JEN network for the forthcoming regulatory control period. On 4 and 7 June 2010 the AER issued its draft determination[1] and decision[2], and supporting materials, respectively.

JEN has considered carefully the AER's draft decision on JEN's regulatory proposal, and the reasons that the AER has provided for its preferred amendments, in the light of the national electricity law (**NEL**) and National Electricity Rules (**Rules**). Accordingly, JEN has incorporated some of the AER's amendments in its revised regulatory proposal and not others. This document sets out JEN's reasoning.

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1 AER, *Draft, Jemena Electricity Networks (Victoria) Ltd, Distribution determination 2011–2015*, 4 June 2010 (**draft determination**).

2 AER, *Draft decision, Victorian electricity distribution network service providers:* Distribution *determination 2011–2015,* 4 June 2010 (**draft decision**).

Significance and challenges of this review

This is the first electricity distribution pricing review that the AER has undertaken for Victorian distribution network service providers (**DNSPs**) and the first review JEN has participated in under the new NEL and the Rules. All participating parties, including JEN and the AER, are meeting the challenges of dealing with this new regime. JEN is actively engaging with the AER and stakeholders to foster a common understanding of the complex issues surrounding its regulatory proposal review—many of them new to the AER and specific to JEN and the Victorian DNSPs—and the issues raised by the draft decision.

The new regulatory framework is similar to the previous one in Victoria for very good reasons. Capital intensive businesses such as JEN require transparent and predictable regulatory incentives and decisions. These incentives and decisions underpin the significant investment necessary for JEN to make so that it can provide quality services to its customers at the lowest sustainable cost over the long term.

Major need for new capital expenditure

JEN's extensive analysis and risk assessment continues to strongly indicate that JEN's network remains in significant need of increased investment in system reinforcement, refurbishment and replacement to mitigate capacity constraints, maintain reliability of supply and meet new customer demand. Many of its network and non-network assets are reaching the end of their lives.

In the light of the concerns the AER expressed in its draft decision, and as part of JEN's on-going planning process, JEN has reviewed its forecast capital expenditure, refined its program, and developed more detailed descriptions of the projects that are necessary and why. The imperatives for new major expenditure in the next regulatory period, and JEN's commitment to deliver it as planned, remain clear. The new material that JEN submits with this revised regulatory proposal puts that beyond doubt.

The AER's draft decision on capex allowance is not sufficient to meet these needs. It would result in further decline in asset condition and increased security of supply risks over the next regulatory control period.

JEN is facing difficult challenges with a significant reduction in the surplus network capacity of the past, increases in peak demand from the growth in air-conditioning, and as the network approaches an average age of 50 years, reaching the end of its life, JEN must begin to replace assets before performance deteriorates and costs escalate.

Accordingly, JEN will invest a total of $621 million in its network and information technology over 2011-2015. Major new projects include:

- *Four new zone substations* – JEN will procure land and construct new zone substations in Broadmeadows South, Craigieburn, Alphington and Tullamarine to meet network expansion requirements arising from growth in the customer base.

- *Distribution substation augmentations* – JEN will augment over 1,000 distribution substations to ensure current performance is maintained amid growing customer demand and increasing weather severity arising from climate change.

- *Major IT projects* – JEN will undertake extensive systems investment including replacing its SAP enterprise asset management system and building a disaster recovery data centre, and establishing a geographical information system.

- *Broadmeadows depot* – JEN will create a new depot that will better fulfil our occupation health and safety requirements and enhance our workforce capacity.

Weighted average cost of capital and tax

The commercial viability of new investment is largely dependent upon the return on capital JEN is allowed and, based on the agreed averaging period, JEN proposes a nominal vanilla WACC of 10.29 per cent.

In this revised regulatory proposal, JEN's cost of capital calculation incorporates many of the AER's amendments where, at this stage, JEN provides no persuasive evidence to move away from parameters set in the AER's Statement of Regulatory Intent (**SORI**) except in relation to the valuation of imputation credits (gamma).

JEN reaffirms that, as set out in its original regulatory proposal, 0.2 is the best estimate of gamma on a reasonable basis in the current circumstances. That is, adopting a value of 0.2 for gamma will provide JEN with, in an overall sense, a rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services, and is consistent with the national electricity objective and the revenue and pricing principles. In this revised regulatory proposal, JEN demonstrates that both the AER's and JEN's experts support JEN's view.

JEN's proposed cost of debt reflects the risks of an efficient electricity distributor and the prevailing market conditions. JEN has built on recent work to identify the best estimate of the debt risk premium from available data service providers and puts forward a methodology that incorporates a number of robust tests. One key element of the methodology is to test the appropriate extrapolation of observed yields.

Operating expenditure

Independent benchmarking shows that JEN's operating costs compare very favourably with its peers. This may in part reflect the significant economies of scale and scope from which JEN is able to benefit through outsourcing to Jemena Asset Management (**JAM**) and its relationship with the Jemena Group.

JEN forecasts operating expenditure that continues to reflect those benefits, along with step changes necessary for JEN to meet new and emerging regulatory obligations and deliver its planned capital investment.

The asset management agreement that JEN has struck with JAM provides substantial benefits to JEN, its users and its customers in terms of both price and service. JEN's position within the Jemena Group also provides scale benefits in terms of the overheads that all corporations bear. In this document, JEN puts forward both an assessment framework and its application to confirm that the price JEN will pay, and the service it will receive, is the best it could achieve.

Demand forecasts

Under the current price regulation framework, reliable demand forecasts are essential to ensure that DNSPs are able to recover at least their efficient costs. JEN has now updated its forecast with regard to the latest economic data, and has specifically taken account of Government climate change and energy efficiency policies that will come into effect in the future—such as the introduction of advanced metering infrastructure.

Frontier Economics has also conducted a detailed critique of NIEIR's model and methodology, upon which JEN's forecast is based. It found NIEIR's modelling system meets world's best practice standards. Frontier Economics also estimated the impact that various Government energy policies will have on energy consumption. It confirmed the impacts are material and JEN has incorporated the adjustments to its consumption forecasts to properly take them into account.

JEN has not understated its energy growth forecasts, JEN has presented forecasts in this revised regulatory proposal that are a realistic and balanced presentation of likely outcomes over the next regulatory control period. Further, the forecasts have been subject to expert peer review which has demonstrated that the assumptions behind the forecasts are reasonable.

Transmission charges pass-through

Since its inception, a fundamental element of the electricity distribution regulatory framework has been that DNSPs provide the means by which charges for transmission services are passed through to customers. The AER has accepted this and successfully applied the current rules to its electricity distribution decisions for NSW, the ACT, Queensland and South Australia. For the Victorian review, however, the AER has cast significant doubt on the current rules with the result that there is now a risk that Victorian distribution businesses may bear some of these transmission charges themselves.

JEN's view is that the current rules provide adequately for the pass-through of transmission charges. An unnecessarily narrow interpretation of the rules, which could require distribution businesses to bear these charges, creates substantial new regulatory uncertainty that could adversely affect investment in the sector.

Further responses to draft decision

This document is JEN's initial response to the AER's views in its draft decision. The document also describes how JEN has revised its regulatory proposal to address matters raised by the draft decision. JEN may make subsequent responses in support of its revised regulatory proposal.

1 Introduction

- This document comprises JEN's revised regulatory proposal and interim response to the AER's draft determination and draft decision in accordance with rule clauses 6.10.2 and 6.10.3.
- JEN looks forward to working with the AER and users in the lead up to the final determination.
- JEN notes that the regulatory review process under the Rules will be most effective where distribution network service providers (**DNSPs**) are consulted and afforded the opportunity to make submissions on the AER's assessment methods and proposed decisions, particularly where these differ from those published in the draft decision.

1.1 JEN's revised regulatory proposal

The AER published its draft decision on Jemena Electricity Networks (Vic) Ltd's (**JEN**) regulatory proposal for the Victorian electricity distribution network (**JEN network**) for the period 1 January 2011 to 31 December 2015, in June 2010. This document comprises JEN's interim response to the draft determination and draft decision, and its revised regulatory proposal (together, JEN's **revised regulatory proposal**).

This chapter sets out the background to the revision process to date, the purpose and structure of JEN's revised regulatory proposal, and the general comments that JEN wishes to make on the draft decision at this stage.

1.2 Background

On 4 and 7 June 2010 the AER issued its draft determination and decision, and supporting materials respectively, under clause 6.10.1 of the National Electricity Rules (**Rules**). This followed a public forum on JEN's original regulatory proposal[3] and public submissions on JEN's original regulatory proposal.

The AER's draft determination was not to approve JEN's regulatory proposal submitted on 30 November 2009.

Under the Rules, JEN has until 20 July 2010 to submit any revised regulatory proposal to the AER. The AER has provided until 19 August 2010 for written submissions on its draft determination and draft decision.

[3] The AER held a public forum on its draft determination and draft decision on JEN's original regulatory proposal in Melbourne on 15 June 2010.

1.3 Purpose, conventions and structure of this document

1.3.1 Purpose

In this revised regulatory proposal, JEN has made revisions to its proposal so as to incorporate the substance of any changes required to address matters raised by the draft decision or the AER's reasons for the draft determination. JEN has provided the reasons for the amendments that it has incorporated into this revised regulatory proposal.

JEN may provide additional information and material to the AER during the course of the AER's consultation on its draft decision; in response to the AER's questions; or to respond to other new or relevant information - for example, stakeholder submissions – that becomes available to JEN during the course of the AER's consultation and prior to the AER making its final determination.

1.3.2 JEN is the network owner

JEN owns and operates the JEN network.

Throughout its draft determination, draft decision and related documents the AER refers to Jemena Electricity Networks (Vic) Ltd as 'Jemena'. JEN requests that the AER refers to Jemena Electricity Networks (Vic) Ltd as 'JEN' in its final determination and related documents.

JEN is the correct legal entity. Using the abbreviation 'JEN' is consistent with JEN's submissions and correspondence on this matter. It will also help avoid stakeholder confusion between JEN and other entities within the Jemena Limited and SPI (Australia) Assets Pty Ltd group, such as Jemena Gas Networks (NSW) Ltd and Jemena Asset Management Pty Ltd.

1.3.3 Monetary amounts

All monetary amounts presented in this revised regulatory proposal are expressed in real 2010 dollars, are in millions of dollars and apply to 1 January to 31 December regulatory years unless otherwise stated.

1.3.4 Structure

The structure of this document mirrors the structure of the AER's draft decision so that it can be easily reconciled to the AER draft decision and draft determination and aid reader understanding. Each chapter addresses the equivalent chapter of the AER draft decision and discusses JEN's original proposal, the AER amendments relevant to the content of that chapter, JEN's response to those amendments and any amendments made to JEN's revised regulatory proposal to address the matters raised in the draft determination and decision.

The chapters in this document are as follows:

- Chapter 2 Classification of services
- Chapter 3 Arrangements for negotiation
- Chapter 4 Control mechanisms for standard control services
- Chapter 5 Growth forecasts
- Chapter 6 Outsourcing and related party margins
- Chapter 7 Forecast operating and maintenance expenditure
- Chapter 8 Forecast capital expenditure
- Chapter 9 Opening asset base
- Chapter 10 Depreciation
- Chapter 11 Cost of capital
- Chapter 12 Estimated corporate income tax
- Chapter 13 Efficiency carryover amounts for 2006-2010
- Chapter 14 Efficiency benefit sharing scheme
- Chapter 15 Service target performance incentive scheme
- Chapter 16 Pass through events
- Chapter 17 Demand management incentive scheme
- Chapter 18 Revenue
- Chapter 19 Public lighting
- Chapter 20 Other alternative control services
- Chapter 21 Outcomes and monitoring compliance.

In addition to these chapters which mirror the AER's draft decision structure, JEN has also prepared an appendix for each chapter which sets out the relevant issues raised in the AER's draft decision (and its consultant's reports) and provides a reference to where the AER can find JEN's specific response. These appendices are appendices: 3.1, 4.1, 5.1, 6.1, 7.1, 8.1, 9.1, 10.1, 11.1, 12.1, 13.1, 14.1, 15.1, 16.1, 17.1, 18.1, 19.1, 20.1 and 21.1.

1.4 Framework and approach issues associated with the draft determination

While other chapters of this document deal with the nature of JEN's revised regulatory proposal and specific issues in the draft determination and draft decision, this section sets out a range of general framework and approach issues associated with the draft determination.

1.4.1 AER reasoning in the draft decision

The draft decision contains a very large number of issues for JEN to consider and respond to in a short period of time. JEN has done its best to address all the issues based on its understanding of the reasoning in the draft decision.

There are a number of areas in the draft determination and decision in which the AER's reasoning is not apparent to JEN, and in relation to which JEN sought clarification from the AER within the time available.[4]

Beyond the reasoning the AER has provided in its draft decision, and the explanations the AER provided subsequently, JEN reasonably assumes that there are no other working papers that informed material elements of the draft determination and that contained relevant research and/or underlying analysis not contained in the draft decision.

1.4.2 "Fit for purpose" decision making framework

In its report to the Ministerial Council on Energy, the Expert Panel on Energy Access Pricing (**Expert Panel**) discussed three alternative options to characterise the nature of the regulator's decision making power. The Expert Panel described these three alternatives as:

> "(a) to receive and consider a proposal and submissions and determine in relation to each component an outcome that in the regulator's view best meets the criteria (*receive–determine*); or
>
> (b) to assess the regulated entity's proposal and accept it (in whole or in part) unless it fails to meet specified criteria and only in those circumstances to determine an outcome that best meets the criteria, i.e. should there be the *presumption* of acceptance (*propose-respond*); or
>
> (c) to acknowledge that, in any gas access proposal / electricity network service provider offering, there is such a range of dimensions (and inter-relationships

[4] JEN, Letter to the AER, 29 June 2010, *Clarification of AER's reasons for draft determination*.

> between these and pricing and revenue components) that the capacity to require the regulator to apply either of these approaches, or a more specific test to different elements of the proposal, should be retained (*fit for purpose*);…[5]

After considering the above characterisations of the decision-making framework, the Expert Panel recommended that a "fit-for-purpose" decision-making framework be adopted. The Expert Panel stated:

> "…the Panel ***concludes*** that it is not appropriate for a global presumption to be adopted in the Law or the Rules in favour of the regulator accepting a regulated entity's proposal. Equally, the Panel ***concludes*** that it is not appropriate for the Law to mandate a receive-determine model. The complexity and differing characteristics of each element of the service provider's proposal are such that the Law cannot itself prescribe a single overriding test to be applied by the AER in assessing service provider proposals. These must be determined by the AEMC in the Rules developed for each of the alternative available forms of regulation."[6]

In its response to the Expert Panel's report, the MCE noted the Expert Panel's discussion on the three possible characterisations of the decision-making framework and adopted the fit-for-purpose decision-making framework. The MCE described the fit-for-purpose decision-making framework in the following way:

> "Between these two models [receive-determine and propose-respond], there is an approach that acknowledges that in a service provider's proposal, there is such a range of dimensions (and inter-relationships between these dimensions and revenue and price components) that the regulatory framework should retain the capacity to require the regulator to apply either of these approaches, or a more specific test to different elements of the proposal. The Expert Panel describes this as a 'fit-for-purpose' model. The fit-for-purpose model does not give the regulator an absolute discretion to choose between receive-determine or propose-respond for different elements of the proposal. The regulator is guided in its decision-making."[7]

The MCE adopted the Expert Panel's recommendations:

> "…the AEMC will, in formulating the Rules on individual aspects of regulation, specify the weight to be given to a service provider's proposal and the criteria and basis for the AER to make its decision in line with the statutory economic efficiency test. The AEMC has already engaged in this analysis in making the transmission revenue

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5 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 60.

6 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 90.

7 Standing Committee of Officials of the Ministerial Council on Energy, *2006 Comprehensive Legislative Package: Overview and Response to Expert Panel on Energy Access Pricing*, p. 17.

rules. The MCE has also had regard to the Expert Panel's analysis in developing the initial NGR [National Gas Rules] and the national electricity distribution rules."[8]

The Second Reading Speech that accompanied the significant amendments to the National Electricity Law noted the following important points in connection with the fit-for-purpose framework:

- that the fit-for-purpose decision making framework is a key aspect of the regulatory framework established by the Bill

- that it reflects the MCE policy intention to establish a fit-for-purpose decision-making model by allowing the Rules to set out the decision-making framework and determine the level of discretion the AER has in dealing with the different aspects of a regulatory determination

- it acknowledges that, for the purposes of making a regulatory distribution determination, there is often such a range of revenue and price components (and inter-relationships between them), that it may be appropriate in some cases for the regulator to be required to accept a reasonable proposal put forward by a service provider. In other cases, it will be appropriate to leave the regulator with the discretion to determine an outcome, or even to require the regulator to apply a more specific test to different elements of the proposal. Under the fit-for-purpose model, the regulator is guided in its decision-making by the express provisions in the Rules which govern the available level of discretion, along with the national electricity objective and the revenue and pricing principles.[9]

In the context of the economic regulation of electricity distributors, the fit-for-purpose framework is encapsulated in clause 6.12.3 of Chapter 6 of the Rules.[10] Clause 6.12.3 provides amongst other things that:

- subject to clause 6.12.3 and other provisions of Chapter 6 explicitly negating or limiting the AER's discretion, the AER has a discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal

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8 Standing Committee of Officials of the Ministerial Council on Energy, *2006 Comprehensive Legislative Package: Overview and Response to Expert Panel on Energy Access Pricing*, p. 18.

9 Second Reading Speech, National Electricity (South Australia) National Electricity Law – Miscellaneous Amendments) Amendment Bill 2007, The Hon. P.F. Conlon (Elder—Minister for Transport, Minister for Infrastructure, Minister for Energy).

10 Ministerial Council on Energy, *Principle Rules Changes from 1st Exposure Draft*, Energy Market Reform Bulletin No. 105, 5 October 2007, p. 1.

- if the AER refuses to approve an amount or value referred to in clause 6.12.1 (constituent decisions), the substitute amount or value on which the distribution determination is based must be:

  – determined on the basis of the current regulatory proposal

  – amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

Clause 6.12.1 sets out that a distribution determination is predicated on a number of decisions (constituent decisions) by the AER, which include:

- a decision in which the AER either: (i) acting in accordance with clause 6.5.7(c), accepts the total of the forecast capital expenditure for the regulatory control period that is included in the building block proposal; or (ii) acting in accordance with clause 6.5.7(d), does not accept the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors

- a decision in which the AER either: (i) acting in accordance with clause 6.5.6(c), accepts the total of the forecast operating expenditure for the regulatory control period that is included in the current building block proposal; or (ii) acting in accordance with clause 6.5.6(d), does not accept the total of the forecast operating expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors.

The fit-for-purpose decision-making framework set out in Chapter 6 of the Rules incorporates elements of the propose–respond model of decision making in respect of the constituent decisions is clause 6.12.1 of the Rules. As noted above, the Expert Panel defines the propose – respond model of decision making as requiring the regulator to assess the regulated entity's proposal and accept it (in whole or in part) unless it fails to meet specified criteria and only in those circumstances to determine an outcome that best meets the criteria. What this practically requires is first, an assessment by the AER of the service provider's regulatory proposal against the requirements of the Rules and the Law, and then, and only if the service provider's regulatory proposal does not meet these requirements, second, a determination by the AER of a substitute amount or value.

Most relevantly, forecasts of operating and capital expenditure are constituent decisions under clause 6.12.1. The AER is required to accept forecast operating and capital expenditure where:

- those forecasts reasonably reflect the efficient costs of achieving the operating or capital expenditure objectives
- the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the operating or capital expenditure objectives
- a realistic expectation of the demand forecast and costs inputs required to achieve the operating or capital expenditure objectives (as relevant).[11]

Pursuant to clause 6.12.3, it is only where the AER has assessed the service provider's forecasts of, in this example, operating and capital expenditure as not being compliant with the requirements of the Rules, that the AER may then go on to determine a substitute amount or value. However, in determining any such substitute amount or value the AER is required to determine the amount: (a) on the basis of the service provider's proposal; and (b) amended from the service provider's proposal only to the extent necessary to enable it to be approved in accordance with the Rules.

JEN does not consider that the AER has met the requirements of the fit-for-purpose model of decision making incorporated in Chapter 6 in relation to a number of aspects of the draft decision, and specifically, the draft decision is not made in accordance with the propose – respond elements of Chapter 6 in connection with the AER's draft decision on the substitute amounts or values for forecast operating and capital expenditure. This is discussed in greater detail in the relevant sections of this revised proposal.

1.5 Leading up to the final decision

1.5.1 Consideration of confidential information

JEN expects that the AER will have regard to the genuinely confidential information that JEN or stakeholders submit to the AER.

JEN has claimed confidentiality over some of the information JEN has provided to the AER as part of the AER's review of JEN's regulatory proposal. JEN has restricted its claim for confidentiality to genuinely confidential information. JEN does not believe that its claims for confidentiality have any relevant impact on the AER's ability to properly assess whether JEN's proposal is compliant with the NEL and the Rules. If the AER does consider that its ability to fully assess any aspect

[11] Clauses 6.5.6(c) and 6.5.7(c).

of JEN's proposal is hampered by JEN's confidentiality requests, JEN would appreciate being notified of this, and as early as possible, so that JEN can consider whether such information can be made available on a restricted or limited basis.

1.5.2 Consideration of stakeholder submissions and new information/analysis available after the draft decision

JEN must be afforded a reasonable opportunity to respond to all materials that are relevant to the review process, including any new information the AER intends to take into account or any change in thinking on issues upon which the AER has not previously consulted JEN.

Where stakeholders raise new issues in submissions responding to JEN's revised regulatory proposal, or the AER conducts further analysis as a part of making its final determination, JEN has a reasonable expectation that it will have an opportunity to review and, where appropriate, respond to, such submissions and new information prior to the final decision.

1.5.3 Maintaining constructive contact

JEN continues to welcome questions and comments from the AER and from stakeholders on its revised regulatory proposal. JEN will use its best endeavours to address the issues raised and provide additional information if it is needed.

JEN encourages the AER to continue to have a dialogue with JEN and not wait until its final decision to express any view it has about the potential adequacy or reliability of the information JEN has provided. In this way, JEN can respond in a timely manner, especially to correct any misconceptions, and the AER and other relevant stakeholders will be better informed for the AER's final decision.

2 Classification of services

- JEN has incorporated the AER's draft determination on service classification.

2.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN agreed with the classifications set out in the AER's Framework and Approach paper (**F&A paper**), other than the AER's classification of all aspects of competitive and non-competitive components of new connection and augmentation services as negotiated distribution services given that the AER's F&A paper classification of these services:

- was inconsistent with previous arrangements
- would create an unnecessary administrative burden on JEN and its customers in the provision of high volume, routine connection services
- could result in all customers paying at the outset the full cost of connection assets through connection charges, rather than through a combination of connection charges and ongoing network charges.

Therefore, JEN proposed to classify all new connection and augmentation works as standard control services. JEN noted that its proposed classification was consistent with current classification of services and is more appropriate under the new regulatory framework than that proposed by the AER.

Table 2-1 highlights the differences between the AER's F&A paper classification and JEN's classification in the regulatory proposal.

Table 2-1: Differences between AER F&A paper and JEN's original regulatory proposal service classifications

Services	AER F&A Service group	AER F&A Classification	JEN Regulatory Proposal Classification
Connection and augmentation works for new connections – routine connections: • Single phase connection • 3 phase (direct connected meter) connection • 3 phase (CT meter) connection	Connection Services	Negotiated Distribution Service	Standard Control Service
Connection and augmentation works for new connection – non-routine connections	Connection Services	Negotiated Distribution Service	Standard Control Service

2.2 Summary of AER's draft determination and decision

In the draft decision, the AER accepted JEN's proposed service classification, with the exception of routine connection services. While JEN sought these services to be classified as standard control services, the AER's draft decision classifies routine connections as alternative control services.

2.3 JEN's response to AER's draft determination and decision

JEN has reviewed the AER's stated reasons for classifying routine connections as alternative control services. While JEN does not agree with the reasoning for and the appropriateness of the AER's draft decision on service classification, in this revised proposal, and as a pragmatic matter, JEN has incorporated that element of the AER's draft determination which provides that routine connection services should be classified as alternative control services.

3 Arrangements for negotiation

- JEN has incorporated the AER's proposed amendments to its negotiating framework.

3.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN submitted a negotiating framework in accordance with clause 6.8.2(c)(5) of the Rules. JEN's negotiating framework was structured as follows:

- Section 1 – Application of negotiated framework
- Section 2 – Timeframes
- Section 3 – Provision of commercial information by service applicant
- Section 4 – Provision of commercial information by JEN
- Section 5 – Pricing principles
- Section 6 – Consultation with affected parties
- Section 7 – Payment of JEN's costs
- Section 8 – Termination of negotiations
- Section 9 – Publication of results of negotiation
- Section 10 – Dispute resolution
- Section 11 – Giving notices
- Section 12 – Terms and abbreviations.

3.2 Summary of AER's draft determination and decision

In section 5 of its draft determination the AER did not approve JEN's proposed negotiating framework because it believed that it did not fully comply with the requirements of clause 6.7.5 of the Rules. The AER's reasons for not approving the negotiating framework are as set out in section 3.5 of its draft decision.

The AER set out in Appendix C.3 of its draft decision the required amendments to JEN's negotiating framework before it can approve it in accordance with the Rules.

The amendments include:

- removal of paragraph 2.2.2
- removal of the number and sentence '4.1.2 For the purpose of paragraph 4.1.1C', to be replaced with '4.1.3 For the purpose of paragraph 4.1.2C'.
- amendments to section 7 as shown in Appendix C.3 of the AER's draft decision.

3.3 JEN's response to AER's draft determination and decision

JEN accepts the AER's required amendments without change. JEN's revised negotiating framework is shown in Appendix 3.1 (clean copy) and Appendix 3.2 (marked up copy).

4 Control mechanisms for standard control services

- Since 2000, Victorian DNSPs have recovered transmission use of system (**TUOS**) costs, transmission connection costs, internetwork charges and payments to embedded generators through the transmission revenue control formula. The AER considered that only TUOS costs were recoverable under rule 6.18.7, yet the AER provided no mechanism for recovery of the remaining costs. DNSPs must be afforded an opportunity to recover their efficient costs of providing network services and JEN has proposed a pass through control mechanism to enable this in a transparent manner.
- Several elements of the AER's proposed weighted average price control require revision. They are:
  - *the L factor specification*—to ensure the AER's intent of full licence fee recovery is preserved
  - *the S factor true-up*—to provide certainty of cost recovery for DNSPs amid a final determination that will be reliant on estimated 2010 service performance
  - *the formula*—to ensure correct application of the price control where tariff reassignment occurs
  - *specification of the 'pass through' parameter*—in a manner consistent with the other price control parameters.
- The AER's proposed side constraint on tariff class rebalancing requires minor amendment to: accommodate circumstances where a new tariff is being introduced, align the pass through parameter with others, and allow the constraint to function when a customer is reassigned between tariff classes.
- The AER's proposed assignment and reassignment requirements are significantly more onerous than currently apply which will cause JEN to incur additional costs not contemplated in its original proposal and which JEN considers can be avoided by JEN's proposed amendments.

4.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN interpreted the AER's F&A Paper to mean that the weighted average price cap (**WAPC**) parameters for standard control services and the maximum transmission revenue (**MTR**) formula have the definitions currently in the Essential Service Commission of Victoria's (**ESCV**) *Electricity Distribution Price Review 2006-10 Final Decision Volume 2 Price Determination* as amended for the appeal (**ESCV price determination**) for prescribed distribution services. JEN proposed that:

- the current specification of the S factor parameter in the standard control services WAPC be amended to accommodate the introduction of the AER's new Service Target Performance Incentive Scheme (**STPIS**) arrangements
- the definitions of the S factor '(1+St)' and the L factor '(1+Lt)' be amended to align with the ESCV by including a single St and Lt factor, or modifying the AER definition to achieve transitional cost recovery
- the definition of payments to embedded generators in the maximum transmission revenue formula include rebates made and administrative costs incurred by JEN under the Victorian premium feed-in tariff (**PFIT**) regime.

4.2 Summary of AER's draft determination and decision

The AER's draft determination included five key parts:

1. the WAPC for standard control services
2. the tariff rebalancing constraint for standard control services
3. tariff reassignment requirements
4. tariff reassignment assumptions and price path calculation
5. the MTR formula.

4.2.1 WAPC for standard control services

The AER's draft decision largely retained the current WAPC price control for standard control services with:

- slight modification to the S factor service incentive adjustment and the L factor licence fee pass through to address issues JEN identified in its original regualtory proposal
- addition of a qualitative 'pass through' parameter into the WAPC.

The draft decision also rejected the proposal by JEN, CitiPower, Powercor and United Energy Distirbution (**UED**) that the S factor true-up adjustment to account for the AER discontinuing the former ESCV service incentive scheme should apply to tariffs in 2012. The AER favoured a true-up adjustment to the building blocks at the 2016-2020 review.

4.2.2 Tariff rebalancing constraint for standard control services

The AER's draft decision set the tariff class rebalancing constraint at the greater of:

- the (CPI – X) limit on the increase of a DNSP's expected weighted average revenue between the two regulatory years plus 2 per cent
- (CPI + 2 per cent).[12]

The AER also specified that this rebalancing constraint would apply at a tariff class rather than a tariff level and would not apply between regulatory periods or to tariff classes relating to AMI to enable time of use (**TOU**) prices in accordance with the Rules.

4.2.3 Tariff assignment and reassignment requirements

The AER's draft decision establishes an obligation for DNSPs to implement an extensive system of tariff assignment and reassignment assessment and review processes. These are significantly more onerous than the current process. They include new requirements for DNSPs to notify customers directly of the tariff class to which the customer has been assigned (as distinct from reassigned) instead of their retailers as well as interposing the Energy and Water Ombudsman of Victoria (**EWOV**) in the dispute resolution process instead of former arrangements that placed this responsibility with the AER (and previously the ESCV).

4.2.4 Tariff reassignment assumptions and price path calculation

The AER's draft determination requires DNSPs to apply the NPV price path calculation in the AER's post tax revenue model (**PTRM**) assuming no tariff reassignments. While the AER does not intend this to constrain DNSPs' ability to reassign customers during the regulatory period and recovery their allowed revenue requirements, it is intended to preserve the consistent calculation of required annual price movements.

4.2.5 MTR formula

The AER's draft determination significantly modifies the definitions of recoverable costs under the MTR relative to current arrangements. The draft determination provides no means of recovery for costs formerly recovered through the MTR including: transmission connection charges, inter-network charges and avoided

[12] Draft decision, p. 60.

DUOS and TUOS payments to embedded generators. Further the AER rejected JEN's proposal to include recovery of PFIT costs through the MTR formula.

4.3 JEN's response to AER's draft determination and decision

In the following sections JEN sets out its response to the four key parts of the AER's draft determination on control mechanisms for standard control services.

4.3.1 WAPC for standard control services

JEN notes that the AER's draft determination largely retains the current WAPC price control for standard control services and that the AER's amendments address JEN's concerns by modifying the L factor to ensure consistent cost recovery as JEN transitions to a new regulatory period and new WAPC.

Four areas of the WAPC that require revision are: the L factor specification; the S factor true-up; application of the WAPC where tariff reassignment occurs; and specification of the 'pass through' parameter.

L factor specification

The AER's draft decision states that the L factor should roll through the reset year to enable recovery of 2009 and 2010 licence fees.[13] However, the formula specified in Appendix E of the draft decision sets *L* to zero for 2011 and 2012 which prevents the roll through working.[14] The clauses setting *L* to zero in 2011 and 2012 should be removed.

S factor specification

The AER's draft decision does not specify how the S factor in the AER's proposed WAPC will be calculated. JEN requests that the AER publish its proposed S factor parameter specification for consultation. This is particularly important given that issues raised in the DNSPs' original proposals and summarised in the draft decision do not appear to have been addressed.

S factor true-up adjustment

The AER has determined that the ESCV S factor should be wound up and that JEN should transition to the AER's new STPIS scheme. It is incumbent on the AER to provide a means of preserving the financial impact on JEN through this transition.

13 Draft decision, p. 57.

14 Draft decision, Appendix E.2 p. 14.

The AER's proposal for a true-up adjustment to the 2016-2020 building block revenue requirement at the 2015 price review does not adequately address JEN's concerns regarding fair and accurate true-up for the transition to the AER's proposed STPIS scheme.

JEN is concerned that the AER cannot bind itself or any future regulator to give effect to statements of intent at the next price review. These concerns are warranted given the AER's rejection of JEN's proposal to recover the financing costs on capex overspends as foreshadowed by the ESCV.[15]

Further, JEN notes that one of the reasons the AER states for rejecting JEN's S factor true-up proposal is that the Rules constrain the AER to follow its WAPC formula in its F&A paper. JEN notes that this reasoning is at odds with its introduction of an entirely new 'pass through' pricing parameter into this WAPC formula.

JEN considers the best solution is JEN's proposed adjustment to 2013 tariffs. If the AER cannot provide a dedicated adjustment or pass through, then it should include this adjustment within the specification of its own STPIS for the first year in which this applies to JEN's tariffs.

Accommodating changes to tariff structures in the WAPC

The AER must ensure that the WAPC formula will operate accurately when changes to tariff structures,[16] such as tariff reassignments, occur. JEN considers the draft determination on WAPC requires amendment to achieve this.

The AER's draft determination on WAPC is:

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

JEN considers that this should be specified as:

15 Draft decision, p. 449.

16 As defined in the draft decision, Appendix E.1, p. 8.

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

Where a DNSP has *n* distribution tariffs, which each have up to *m* distribution tariff components, and where:

- *regulatory year "t"* is the regulatory year in respect of which the calculation is being made
- *regulatory year "t–1"* is the regulatory year immediately preceding regulatory year *"t"*
- *regulatory year "t-2"* is the regulatory year immediately preceding regulatory year *"t–1"*
- P^{ij}_t is the proposed distribution tariff for component *j* of distribution tariff *i* in regulatory year *t*
- P^{ghij}_{t-1} is the distribution tariff being charged in regulatory year *t–1* for component *j* of distribution tariff *i* and component *h* of distribution tariff *g* where a change in tariff structure occurs
- q^{ij}_{t-2} is the quantity of component *j* of distribution tariff *i* delivered in regulatory year *t-2*
- q^{ghij}_{t-2} is the quantity delivered in regulatory year *t-2* against component *j* of distribution tariff *i* and component *h* of distribution tariff *g* where a change in tariff structure occurs
- CPI_t is calculated as follows:

  The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australian Bureau of Statistics for the September Quarter immediately preceding the start of *regulatory year t*

  divided by

  The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australian Bureau of Statistics for the September Quarter immediately preceding the start of *regulatory year t–1*

  minus one.

Addition of the $p_{t-1}^{ghij} q_{t-2}^{ghij}$ parameters is necessary to implement the WAPC when a change in tariff structure, such as tariff reassignment, occurs as contemplated in

Appendix E of the AER's draft decision. Appendix 4.2 provides a worked example of how this WAPC will operate in a situation where a tariff reassignment occurs.

This is necessary to comply with the implications of Appendix E of the draft decision for tariff reassignment. In this context, JEN notes that:

$$q_{t-2}^{ij} = \sum_{g=1}^{n} \sum_{h=1}^{m} q_{t-2}^{ghij}$$

Pass through parameter

JEN considers that failure to specify the "passthrough" parameter in a formulaic manner together with the likely compounding effects of trying to implement this parameter along with the L factor and S factor create significant uncertainty and potential for inadequate cost recovery where this parameter is called upon.

JEN proposes removal of the "passthrough" from the WAPC and establishment of a dedicated control mechanism that allows the recovery of all pass through costs. This would include both identified distribution pass through costs and those formerly recovered through the MTR.

JEN describes its proposed pass through control mechanism in section 4.3.6.

JEN notes that while this control mechanism was not contemplated in the AER's F&A Paper, neither was the AER's "passthrough" parameter.

Should the AER decide to retain this parameter in the WAPC formula, JEN considers this requires amendment. The AER's proposed 'passthrough' would be expressed as a percentage and therefore should be a factor (positive or negative) like any other price control parameter in the WAPC. This means the "+/-" part of the AER's proposed WAPC is redundant and should be removed to avoid confusion or unintended consequence. Replacing the term "+/- (passthrough$_t$)" with "x (1+ passthrough$_t$)" ensures all elements of the WAPC formula (ie CPI, X, L, S and passthrough) are treated in a consistent manner.

4.3.2 Tariff rebalancing constraint for standard control services

JEN agrees with the intent and broad specification of the tariff rebalancing constraint in the AER's draft determination. However, JEN considers the formula for this constraint requires slight amendment to:

- accommodate circumstances where a new tariff is being introduced as discussed above
- correct for the '+/-' issue with the passthrough parameter as discussed above

- allow application of the constraint in circumstances where a customer is reassigned between two tariff classes.

The AER's draft determination set out the tariff rebalancing constraint as:

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

JEN considers that this should be:

$$\frac{\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_t^{cij} q_{t-2}^{cij}}{\sum_{g=1}^{n}\sum_{h=1}^{m}\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_{t-1}^{ghcij} q_{t-2}^{ghcij}} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\times(1+0.02)$$

Where each tariff class *c* has n^c tariffs, with up to m^c components and where for each tariff class *c*:

- *regulatory year "t"* is the regulatory year in respect of which the calculation is being made
- *regulatory year "t–1"* is the regulatory year immediately preceding regulatory year *"t"*
- regulatory year "*t-2*" is the regulatory year immediately preceding regulatory year "*t–1*"
- tariff *i* and component *j* represent the proposed pricing segment in year *t*, whereas tariff *g* and component *h* represent the source pricing segment from year *t-1* that has been mapped to tariff *i* and component *j*. Tariff *g* and component *h* are not necessarily of the same tariff class as tariff *i* and component *j*, if tariff reassignment between classes occurs
- P^{cij}_t is the proposed distribution tariff for component *j* of distribution tariff *i* in regulatory year *t*
- P^{ghcij}_{t-1} is the distribution tariff being charged in regulatory year *t–1* for the subset of component *j* of distribution tariff *i* that was mapped from the source component *h* of source tariff *g*. If there is no changes to tariff structures then *g=i, h=j*, and $p^{ghcij}_{t-1} = p^{cij}_{t-1}$

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

- $q^{ghcij}_{t\text{-}2}$ is the audited quantity from regulatory year *t-2* for the subset of component *j* of distribution tariff *i* that was mapped from source component *h* of source tariff *g*. If there is no changes to tariff structures then *g=i* and *h=j*. Note that source tariff *g* and source component *h* are not necessarily of the same tariff class *c*.

- CPI_t is defined as set out in the WAPC formula:

Appendix 4.2 provides a worked example of how this side constraints will work in a situation where a tariff reassignment occurs.

JEN notes that it has five tariff classes to which this constraint would apply:

1. residential
2. small business
3. large business - low voltage
4. large business - high voltage
5. large business - subtransmission.

JEN understands the AER's proposal is to apply the side constraint to these tariff classes, and that the applicable tariffs within each of JEN's tariff classes are as set out in Appendix 4.3.

JEN notes that the modified formula specification it has proposed above removes the '*c*' parameter from the denominator. While JEN agrees this is necessary for the numerator, it cannot be applied to the denominator as this would constrain application of the side constraint to reassignments *within* a given tariff class.

JEN notes that reassignment can occur *between* tariff classes and the side constraint must accommodate this. For example, a customer may have significantly reduced their load which requires the customer to be reassigned from a tariff in the large business low voltage tariff class to a tariff in the small business tariff class. JEN's proposed amendment will accommodate this and preserve the correct application of the side constraint.

4.3.3 Tariff reassignment requirements

The AER's proposed reassignment requirements are significantly more onerous than currently applied to JEN's network which JEN expects will cause it to incur additional costs not contemplated in its original regulatory proposal. JEN sets out below the key issues associated with the AER's draft determination on assignment and reassignment requirements. Details of the new step change required to implement the AER's requirements are set out in Appendix 7.2.

JEN's concerns with the AER's proposal relate to the requirement to notify customers instead of their retailer and the interposition of EWOV within the tariff assignment dispute resolution process.

Assignment process

Clause 6 in Appendix G of the AER's draft decision requires Victorian DNSPs to notify a customer in writing of the tariff class to which the customer *will be* assigned or reassigned, prior to the assignment or reassignment occurring. Specifically, clause 6 of Appendix G states:

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

Currently Victorian DNSPs must comply with a similar regulatory obligation in clause 2.1.20 of the ESCV price determination which states:

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

There are similarities in the clauses. By inserting the words 'assigned' and 'reassignment' to capture notification for both circumstances, JEN considers clause 6 becomes unwieldy. The words 'has been assigned' and 'prior to the assignment' in clause 6 appear to be inconsistent. If a DNSP is required to notify the tariff the customer has been assigned, it can only be done after the assignment – not prior.

JEN understands that the AER requires notification of tariff assignment to ensure compliance with the clause 6.14.4 (d) of the Rules. That is, customers should be provided with an opportunity to object to the proposed tariff assignment and that there must be an effective system of assessment and review. Additionally, the clause should provide for a customer to seek reassignment of their existing tariff class to a more appropriate tariff as circumstances may change.

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

Issues with notification of tariff assignment for customer connections

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

Nintey five per cent of JEN's distribution customers are small customers. Customers who require new connections generally approach a retailer of their choice and arrange the connections.

When a customer enters into a retail contract with their retailer, the retail tariff is inclusive of the DNSP's network tariff, which is bundled into the retail tariff.

Large customers generally negotiate directly with the DNSP on the most suitable network tariff class having regard to their load and connection characteristics. This negotiation takes place at the same time as the customer negotiates the supply connection with the DNSP. It is worth noting that the connection charge payable by the customer can only be determined after agreement is reached with the customer on the applicable network tariff class. This is because the DNSP must know the future tariff revenue in order to calculate any required up-front connection charge net of expected revenues.

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

JEN receives approximately 25,000 energisation requests (fuse inserts) each year via the B2B process from retailers. Most relate to properties that have been previously connected. Under Clause 6 of Appendix G of the draft decision, a DNSP is required to notify the customer of the tariff class to which the customer will be assigned. JEN believes the DNSP's notice will only serve to confuse customers, given that they have instructed their retailer to arrange energisation, agreed to a retail tariff (inclusive of a network tariff) and entered into a retail contract.[17] Moreover, the written notice will be marked attention to 'The Customer' because not all retailers provide the customer's name on the B2B service orders.

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

[17] JEN notes that this logic regarding retail confusion was a factor in the AER's *Interval Meter Reassignment Requirements Final Decision*, May 2009, p. 21.

associated with tariff assignment notification including customer call handling and ombudsman costs is shown in Table 4-1. JEN has included these costs as an opex step change in section 7.3.6 and Appendix 7.2.

Table 4-1: Estimate of costs to implement tariff assignment notification obligation

Estimate	Details	Cost pa
Total of 31,500 notifications per annum	• Approximately 25,000 customer move-ins per annum • Approximately 6,500 new connections per annum	
Cost of notification	$1per notification notice 32,000 notifications	$32,000
Cost of handling customer calls	Assume 10% of the customers will call to enquire why the charge on their bill is different to that on the notice • 3,200 call centre inquiries • 320 inquiries escalated to stakeholder relations team	 $75,000 $80,000
Customers that refer the complaints to the EWOV	• 32 investigations referred by the EWOV to JEN to resolve • EWOV fee $790 per case	$25,000
Total		**$212,000**

JEN's proposed solution to avoid unnecessary and inefficient costs

JEN proposes a way forward regarding compliance with clause 6.14.4 (d) of the Rules that avoids unnecessary costs.

Clause 6.14.4 (d) of the Rules states:

> … a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.

If, for example, a customer is assigned (or reassigned) to a tariff class on the basis of the customer's actual or assumed load characteristics, the system of assessment and review should allow for the reassignment of a customer who demonstrates a change in their load characteristics to a tariff class that is appropriate to the customer's load profile.

In JEN's view, an effective system of assessment and review is only required when a customer's tariff is reassigned by the DNSP to another existing or new tariff in accordance with Appendix G. What is required is a system of assessment and review for customers who seek a reassignment of their network tariff class.

The existing systems of explicit or implicit agreement to initial assignments along with current dispute processes represent a perfectly well functioning effective system for assessment and review of assignments.

JEN proposes the following amendment to clause 6 in Appendix G of the AER's draft decision:

> "(a) A Victorian DNSP must notify the customer concerned in writing of the tariff class to which the customer has been ~~assigned or~~ re-assigned~~ by it, prior to the assignment or reassignment occurring~~.
>
> (b) A customer may apply for reassignment of their tariff class."

Dispute resolution through EWOV

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

The current process set out in clauses 2.1.25 to 2.1.28 of the ESCV price determination is:

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

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

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

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

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

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

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

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

This process was originally established under the Victorian Tariff Order clause 5.2.16 and has worked well for some 15 years without EWOV involvement. It is unnecessary and inappropriate to involve EWOV because:

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

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

If the AER retains this change in its final decision, it must compensate DNSPs for the additional costs they will incur. See Table 4-1 and section 7.3.6 for inclusion of additional opex step changes.

Customer notification for AMI time of use tariff reassignments

The AER's draft decision on TOU tariff reassignment required Victorian DNSPs to notify a customer's retailer when they reassign that customer to a TOU tariff following installation of an AMI meter rather than the customer directly.[18] The final decision on TOU tariff reassignment changed this to direct customer notification.[19]

JEN notes that DNSPs do not currently have a direct interface with customers except for the purposes of emergency and fault management. JEN notes that TOU tariff reassignments have not yet been introduced due to the Victorian Government moratorium, so the additional costs arising from new notification relationship inherent in the AER's final decision have not yet been incurred.

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[18] AER, *Interval Meter Reassignment Requirements Draft Decision*, 13 March 2009, p. 18.

[19] AER, *Interval Meter Reassignment Requirements Final Decision*, May 2009, p. 21.

The AER's draft determination requires DNSPs to notify customers rather than retailers when they assign or reassign that customer to a given tariff.

JEN considers this new relationship to be inappropriate for a number of reasons:

- prime responsibility for informing customers about assignment and reassignments must sit with retailers, because it is up to a customer's retailer as to how and to what extent the impact of moving to a given distribution tariff, including a TOU tariff, is reflected in the retail price paid by that customer

- DNSPs are not currently funded to resource themselves for customer tariff assignment education and notification or for billing enquiries.

Given customers do not necessarily see or understand their network tariff within their delivered energy bill and that DNSPs do not currently have resourcing to provide a direct customer relationship in tariff issues, JEN recommended that this notification requirement be amended to specify notification of a customer's retailer.

4.3.4 Tariff reassignment assumptions and price path calculation

JEN has incorporated the AER's draft decision requirement to apply the net present value (**NPV**) price path calculation in the PTRM assuming no tariff reassignments. To do this JEN has left all customers on the tariffs to which they are assigned in 2010.

In doing so, JEN notes that it understands the AER does not intend this requirement to constrain DNSPs' ability to reassign customers during the regulatory period or to recover their allowed revenue requirements amid future reassignments. On this basis, JEN's revised growth forecasts have been developed taking into account the assumed tariff reassignments to TOU tariffs associated with the AMI roll-out. Chapter 9 of Appendix 5.2 explains how NIEIR has incorporated this assumption.

JEN has incorporated the AER's draft decision on tariff reassignment in reliance on the AER's draft decistion to include provisions in the WAPC for recovery of foregone revenues associated with tariff reassignments. The AER's draft decision sets out this recovery provision in the worked example in section E.1.2 of Appendix E. JEN has included in Appendix 4.2 a model showing how it understands this recovery mechanism will work in practice using the AER's example and JEN's proposed amendments to the WAPC and the side constraint formulae.

4.3.5 MTR formula

For the last two regulatory periods, Victorian DNSPs have recovered their TUOS costs, transmission connection costs, internetwork charges and payments to embedded generators through the MTR revenue control formula.

The AER's draft decision concluded that only TUOS costs were recoverable under the MTR due to rule 6.18.7. The AER provided no mechanism for recovery of transmission connection costs, internetwork charges and payments to embedded generators.

The AER noted that a rule change proposal was anticipated and that it would reconsider this issue in the final decision following an Australian Energy Market Commission (**AEMC**) ruling.

JEN notes that UED proposed a rule change to the AEMC on 22 June 2010.[20] UED submitted that this was a non-controversial rule change addressing an apparent lacuna in the Rules.

The AEMC has not yet published this rule change proposal or confirmed that it agrees that it is non-controversial. This means there is a high probability the rule change will not be completed prior to the AER's final dertemination.

JEN considers that the AER should commence consultation on the proposed recovery mechanism for these costs. DNSPs must be afforded an opportunity to understand and comment on the AER's proposed cost recovery arrangements for both the case where this rule change is accepted and where it is not. In its current form, the draft determination MTR does not achieve compliance with clause 7A(2)(a) of the NEL, which provides that:

> (2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> (a) providing direct control network services…

For the above reasons, JEN considers the AER should establish a dedicated pass through control mechanisms as set out below in section 4.3.6.

If the AER does not accept JEN's proposal, then JEN's forecast cost of transmission connection costs, internetwork charges and payments to embedded generators should be included in the forecast opex with provision for annual unders and overs pass through and no materiality threshold thereon.

[20] United Energy Distribution, *Rule change proposal: Amendment to the distribution pricing proposal provisions of the National Electricity Rules to provide for the explicit inclusion of transmission-related and other relevant charges in a distribution network service provider's pricing proposal*, 22 June 2010.

Table 4-2: Forecast former MTR cost recoveries ($ million 2010)

Item	2011	2012	2013	2014	2015
Transmission connection costs, internetwork charges and payments to embedded generators	4.59	4.68	4.65	4.75	4.98

Premium feed in tariffs

The draft decision also rejected JEN's proposal to recover premium feed in tariffs (**PFIT**) through the MTR formula.

As with other transmission cost recovery items discussed above, JEN considers that the AER's draft decision does not comply with the NEL requirement that JEN be provided an opportunity to recover at least its efficient costs. The AER must specify a means for DNSPs to recover these costs.

JEN considers that these costs should be recovered through its proposed proposal pass through control mechanism. This proposal is supported by the 1 July 2010 AEMC rule determination *National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010*. This amendment establishes the Victorian PFIT scheme as a 'jurisdictional scheme' with associated recoverable 'jurisdictional scheme amounts' under the Rules.

4.3.6 Pass through implementation mechanism

JEN proposes establishing a control mechanism to allow all recovery of pass through amounts from separate tariffs to the distribution use of system (**DUOS**) and TUOS tariffs. Under this proposal, network use of system tariffs would comprise DUoS tariffs, TUOS tariffs and pass-through tariffs.

Mechanism design

The proposed revenue control on pass-through tariffs is similar to that described in clause F.2, Appendix F of the AER's draft decision where MTR is substituted with maximum passthrough revenue (**MPR**). Appendix 4.4 provides JEN's proposed specification for the MPR control.

Benefits of JEN's proposed pass through control mechanism

This formula is capable of including all pass through costs from DUOS and former TUOS costs as well as PFIT costs. This means there is no need for a separate transmission tariff pass though or distribution tariff pass through in the WAPC or MTR respectively.

This has the advantage of making the pass through cost recovery process transparent and avoids adding complexity and disturbance to DUOS tariffs. This is important for:

- providing a clear and transparent cost recovery mechansism with audited unders and overs adjustments via the lagged correction factor thereby ensuring no windfall gains or losses which is not possible within the WAPC specification proposed by the AER
- demonstrating compliance with clause 6.18.5 of the Rules
- avoiding compounding revenue gain or loss effects through the interaction of the AER's proposed "passthrough" parameter and the L factor and S factor
- avoiding the effect passthroughs would otherwise have of inflating the P_0.

5 Growth forecasts

- The AER in its draft determination accepted the advice of its consultant, ACIL Tasman, that National Institute of Economic and Industry Research's (**NIEIR**) forecasting methodology was sound but required JEN to amend its growth forecasts for latest available information and for different views on the impact of various policy positions.
- JEN has commissioned updated independent growth forecasts from the NIEIR incorporating actual 2009 electricity consumption and customer data, as well as updated economic drivers and (where necessary) updated policy impacts.
- JEN has adopted the updated NIEIR forecasts with an amendment on the basis that they reflect a realistic representation of the demand forecasts required to achieve the operating and capital expenditure objectives.

5.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal JEN submitted energy and customer number forecasts prepared by NIEIR based on econometric modelling and analysis. JEN also submitted its own peak demand forecasts that were validated at the total network level by NIEIR modelling.

In summary, NIEIR forecast that:

- residential energy consumption will reduce from 1,252 GWh in 2010 to 1,151 GWh in 2015 – an average reduction of 1.7 per cent per year
- business consumption will fluctuate, but decline from 3,033 GWh in 2010 to 2,808 GWh in 2015 – an average reduction of 1.5 per cent per year
- total energy consumption will reduce from 4,339 GWh in 2010 to 4,011 GWh in 2015 – an average reduction of 1.6 per cent per year.

NIEIR's forecasts were based on a significant number of key influences on energy consumption in the JEN region over the 2010-2015 period. These influences included the introduction of many new Victorian and Commonwealth Government energy policy developments that will impact energy consumption, such as the Carbon Pollution Reduction Scheme (**CPRS**), Minimum Energy Performance Standards (**MEPS**) and AIMRO in Victoria.

Overall, NIEIR suggested that these policy developments will succeed in their objective of reducing electricity usage. In addition, these policy changes were forecast in an uncertain economic environment resulting from the global financial crisis of late 2008-early 2009. NIEIR's report indicated that the effects of that crisis are yet to be fully worked out in the Australian and Victorian economies and in the JEN region.

Table 5-1 shows JEN's forecast demand included in its original regulatory proposal.

Table 5-1: Forecast maximum demand, customer numbers and energy consumption from JEN's original regulatory proposal

Item	Forecast year ending					
	2010	2011	2012	2013	2014	2015
Maximum demand (MW)	981.6	1,002.3	1,026.8	1,051.3	1,077.3	1,093.1
Growth (per cent)		2.11	2.44	2.39	2.47	1.47
Customer numbers	305,634	310,957	315,557	319,111	322,702	327,397
Growth (per cent)		1.74	1.48	1.13	1.13	1.45
Energy consumption (GWh)	4,339	4,246	4,201	4,105	4,024	4,011
Growth (per cent)		-2.14	-1.06	-2.29	-1.97	-0.32

Note: Maximum demand is the network coincident maximum demand based on 50 per cent probability of exceedence (**POE**).

5.2 Summary of AER's draft determination and decision

5.2.1 Energy consumption and maximum demand

Table 5-2 sets out the amended forecasts that the AER required in its draft determination.

Table 5-2: AER draft decision forecasts – peak demand, energy consumption and customers *(from table 15 of the draft determination)*

Item	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1,067	1,096	1,134	1,168	1,184
Energy consumption (GWh)	4,439	4,544	4,647	4,725	4,783
Customer numbers	308,296	313,257	317,334	320,907	325,049

Note: The AER has reported average customer numbers. On a year-end basis, numbers are unchanged from JEN's original regulatory proposal.

The AER draft decision also provided that, in order to make the proposal acceptable to the AER, JEN would be required to:

- update gross state product forecast inputs to reflect more recent economic conditions
- replace population growth forecast inputs with ABS Series B for Victoria, disaggregated by DNSP according to current proposal assumptions about each DNSP's regional contribution to Victorian population growth
- amend the CPRS policy assumption to delay the commencement of the CPRS by six months, to 1 January 2012.[21]

The draft decision also required a number of adjustments to JEN's forecasts (based on revised NIEIR modelling) to account for the following policy changes:

- a reduction in the effects of lighting MEPS in 2013, 2014 and 2015[22]
- removal of the effects of the insulation target scheme (post 2010)[23]
- removal of the effects of the one watt standby target[24]
- removal of the effects of AMI and TOU tariffs.[25]

The AER required the above amendments to be made in respect of both energy and peak demand forecasts, with the exception that the AER considered that the estimates provided by NIEIR for the impact of MEPS for lighting for maximum demand were reasonable.[26]

The AER also noted that the numbers reported in table 6.2 of NIEIR's energy sales and customer number reports for hot water have no bearing on the demand forecasts provided to the AER as reductions from customers switching from electric heating to other forms are accounted for within the demand forecast models and not through 'post model' adjustments.[27]

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21 Draft decision, p. 156.

22 Draft decision, pp. 114-15.

23 Draft decision, pp. 120-21.

24 Ibid.

25 Draft decision, p. 155.

26 Draft decision, p. 114.

27 Draft decision, p. 120.

5.2.2 Specific maximum demand requirements

In its draft decision on JEN's peak demand forecasts, the AER noted that:

- In agreeing to ACIL Tasman's recommended adjustments, the AER draft decision sought to reconcile the Victorian DNSPs' ZSS forecasts to NIEIR's top down forecasts, noting the average historical diversity between the two.[28]

- It shared ACIL Tasman's concerns regarding JEN's decision to use its own adjusted starting point maximum demands over NIEIR's as its methodology was overly reliant on a limited number of observations at the time of the 2009 system peak.[29]

For these reasons, the AER considered that a reasonable set of demand forecasts for JEN should reflect the adjustments recommended by ACIL Tasman.[30]

In respect of JEN's spatial demand forecasts (not specified in the draft determination), the AER sought to reconcile the Victorian DNSPs ZSS forecasts to NIEIR's top down forecasts, and produced a series of DNSP adjustments in the draft decision.[31] Whilst acknowledging that these adjustments may not be ideal, the draft decision noted that:

> The Victorian DNSPs will have an opportunity in their revised proposals to propose an alternative method of ensuring an appropriate reconciliation with NIEIR's top down forecasts, which the AER considers to be fundamental in producing reasonable spatial demand forecasts.[32]

5.2.3 AER reasons for not accepting JEN forecasts

In its draft decision the AER did not accept the forecasts submitted by JEN on the grounds that:

- The AER considered that the Victorian DNSPs' forecasts were unreasonable given that they reflect outdated economic growth assumptions. The AER expects more optimistic forecasts to be incorporated into the Victorian DNSPs' revised proposals.[33]

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28 Draft decision, p. 32.

29 Draft decision, p. 128.

30 Ibid.

31 Draft decision, p. 133. The adjustments for JEN are given in Table 5.24, pp. 138-39.

32 Draft decision, p. 133.

33 Draft decision, pp 84-85.

- The AER considered that NIEIR's population forecasts were unreasonably low when compared to historical growth rates and the projected growth forecasts from Treasury and the ABS. Accordingly, the AER rejected NIEIR's population growth forecasts used as an input into NIEIR's energy forecasting models.[34]

- The AER considered that the Victorian DNSPs' forecasts reflected an outdated assumption regarding the CPRS. While the AER did not make any adjustments to reflect this delay, it expected that the Victorian DNSPs would update their forecasts to account for this issue in their revised proposals.[35]

- The AER agreed with the advice it received from ACIL Tasman, and considered the Victorian DNSPs' forecast impact of lighting MEPS should be constrained to the impacts modelled in the the Australian Government's RIS (regulatory impact statement). The AER considered NIEIR's estimated impacts for lighting MEPS should be reduced by approximately 4.5 per cent in 2013, 7.0 per cent in 2014 and 9.2 per cent in 2015.[36]

- Adjustments relating to the insulation target scheme should be removed—the AER noted that the Australian Government announced that the insulation rebate scheme is to be discontinued with the remaining funds in the scheme to fund safety switches for houses with foil insulation and inspections.[37]

- NIEIR (on behalf of the Victorian DNSPs) had not demonstrated evidence of a government policy to implement a one watt target. Further, it was likely the impact of one watt standby appliances had been accounted for under NIEIR's use of average household consumption in its electricity consumption model.[38]

- The AER considered that the Victorian DNSPs' proposed reductions to their underlying forecasts for AMI and TOU pricing impacts were based on unrealistic expectations. The AER considered that the analysis and assumptions used by NIEIR and the Victorian DNSPs were subject to several flaws which were likely to result in the impact on maximum demand being understated and/or overstating the expected reductions in energy consumption. The uncertainties around such expected impacts were considered to be high, and were compounded by recent government announcements regarding the delay and ongoing review of TOU tariffs,

[34] Draft decision, p. 107.

[35] Draft decision, p.117.

[36] Draft decision, p. 114.

[37] Draft decision, p. 120.

[38] Draft decision, p. 120.

> including potential phased introductions and compensation for some customers. As stated, the degree of uncertainty was now such that the AER considered it unreasonable to assume any impact arising from AMI in the forthcoming regulatory control period.[39]

JEN notes that the AER's consultants, ACIL Tasman, found the NIEIR forecasting framework to be generally sound and concluded that (in respect of the energy forecasts):

> While ACIL Tasman has differences of view with regard to some of the forecast input assumptions and has not been given access to any detail regarding NIEIR's proprietary models, NIEIR's approach to forecasting electricity sales is considered to be generally sound.[40]

ACIL Tasman reached a similar conclusion in respect of NIEIR's maximum demand forecasts.[41]

5.3 JEN's response to AER's draft determination and decision

The AER largely relied on the ACIL Tasman analysis and recommendations outlined in the ACIL Tasman reports for its draft decision. JEN has therefore reviewed the ACIL Tasman analysis and recommendations for soundness, and in particular whether they would be capable of providing forecasts which are consistent with the requirements of the Rules.

In revising its growth forecasts, JEN has:

- engaged NIEIR to review and update the assumptions previously used in its November 2009 forecasts, re-run its forecasting model and to update its forecasts where necessary (considered in section 5.4).
- considered a series of expert reports commissioned from Frontier Economics by CitiPower and Powercor which review NIEIR's forecasts and respond to ACIL Tasman:
  - a Frontier Economics review of the NIEIR policy adjustments[42] (CitiPower attached as Appendix 5.6)

[39] Draft decision, p. 155.

[40] ACIL Tasman, *Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, Final report*, 11 May 2010, p. 10.

[41] ACIL Tasman, *Victorian Electricity Distribution Price Review, Review of maximum demand forecasts, Final report*, 11 May 2010, p. 19.

[42] Frontier Economics, *Review of policy adjustments*, report prepared for CitiPower, June 2010.

– a Frontier Economics review of the ACIL Tasman recommendations[43] (CitiPower attached as Appendix 5.7)

– a Frontier Economics review of NIEIR's methodology for forecasting electricity consumption[44] (CitiPower attached as Appendix 5.5).

5.3.1 NIEIR methodology

There are several references in both the draft decision and the ACIL Tasman reports to the limited information available about NIEIR's forecasting methodology. While this is a natural consequence of the proprietary nature of NIEIR's models, JEN recognises that this has been a significant concern to both the AER and ACIL Tasman. The latter said:

> The distribution businesses declined to provide more than a general and high level description of how their forecasts had been prepared on the basis of the confidential and proprietary nature of the NIEIR modelling. Hence while some additional information was provided during the meetings, the overall level of information provided did not meet the transparency and repeatability requirements set out in Section 2.[45]

CitiPower and Powercor engaged Frontier Economics to review NIEIR's methodology. The Frontier Economics report is equally applicable to JEN's region in terms of methodology.

The report was prepared by respected academic and consultant, Dr Robert Bartels. It confirms the soundness of NIEIR's overall methodology.

Key points made in the Frontier Economics report[46] are:

- The capabilities of NIEIR's modelling system meet world best practice standards. In particular, NIEIR's modelling system was able to produce forecasts at a highly disaggregated level. To Frontier Economics' knowledge, no other model in Australia had similar capabilities. These strengths were also noted in a review of NIEIR's forecasting processes for the NEM undertaken in 2005 by KEMA.

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43 Frontier Economics, *Review of ACIL Tasman recommendations*, report prepared for CitiPower, June 2010.

44 Frontier Economics: *Review of NIEIR's methodology for forecasting electricity consumption*, report prepared for CitiPower, April 2010.

45 ACIL Tasman, *Victorian Electricity Distribution Price Review, Review of electricity sales and customer numbers forecasts, Final report*, 11 May 2010, pp. 5-6.

46 Adapted from Frontier Economics, *Review of NIEIR's methodology for forecasting electricity consumption*, report prepared for CitiPower, April 2010, Executive Summary, pp. ii-iii.

- The electricity consumption forecasting equations are based on a standard econometric functional form, and the driver variables and dynamic specifications follow accepted economic and econometric practices. Importantly, the forecasting equations include variables that capture what economists usually consider to be the main drivers of electricity sales – an economic activity variable, the own price (i.e. the electricity price), and the price of the main substitute (i.e. the gas price).

- A variety of econometric techniques, calibration, and informed judgement are used to determine the values of the parameters in the forecasting equations and in the economic modelling system. These approaches are in line with standard practices for estimating large modelling systems.

- NIEIR's methodology for forecasting electricity consumption had all the elements that Frontier Economics considered to be desirable.

- NIEIR's methodological approach to calculating post-model adjustments to account for the impact of policy initiatives that affect electricity consumption was reasonable.

- As a general observation, Frontier Economics noted that the lack of consolidated documentation on NIEIR's methodology had complicated its review. While Frontier Economics accepted that NIEIR's methodology was proprietary, in Frontier Economics' view NIEIR could have considered making available more details of its methodology for forecasting electricity sales in the form of a technical guide.

With regard to the last point above, Frontier Economics observed in a footnote that:

> After completing our review, CitiPower advised us that NIEIR had completed a paper that presents a fairly comprehensive discussion of NIEIR's modelling and estimation processes: NIEIR (April 2010), *Overview of economic and energy forecasting methodologies used at the National Institute of Economic and Industry Research*. This paper arrived too late to be incorporated in our review.[47]

JEN has subsequently obtained the NIEIR paper which is attached at Appendix 5.4 in this revised regulatory proposal.[48] The paper notes that:

> The paper is not a user's manual for electricity forecasting; it nonetheless provides sufficient details for technically minded individuals to partially duplicate many aspects of the modelling exercise.[49]

47 Ibid.

48 NIEIR, *Overview of economic and energy forecasting methodologies used at the National Institute of Economic and Industry Research*, April 2010.

49 Ibid, p. 1.

The NIEIR paper (Appendix 5.4) provides more detail of NIEIR's methodology for forecasting electricity sales in the form of a technical guide. JEN believes that the paper goes some considerable way to meeting the concerns of both the AER and ACIL Tasman for more detail about NIEIR's methodology.

JEN also notes that Frontier Economics considered that it would be prudent to consider whether the rebound effect could have had a material impact on demand related to several energy efficiency initiatives. NIEIR had evaluated only one instance of this effect. The updated NIEIR report has addressed potential rebound effects of various policies.

5.3.2 Population

Frontier Economics comments[50]

JEN believes that ACIL Tasman's estimates are flawed and inconsistent with the principles of best practice that ACIL Tasman describes in Chapter 2 of its report.

It is evident from the workbook calculations that ACIL Tasman applies the ABS Series A population forecasts, despite recommending the use of the ABS Series B forecasts. This overstates the energy use projections.

ACIL Tasman should have compared its estimates against NIEIR's forecasts prior to any policy adjustments. This would result in a much lower estimate of differences between the two.

Frontier Economics concludes:

> Based on our concerns with ACIL Tasman's rough estimates of the effects of this change in population forecasts on energy, and ACIL Tasman's own caveats and qualifications, we recommend against any reliance on these rough estimates.

NIEIR comments[51]

ACIL Tasman considers a population growth of 1.4 per cent consistent with the ABS Series B is appropriate. The impacts on the forecast should therefore be a calculation on the difference between NIEIR growth forecasts (1.2 per cent in 2011-12) and ABS growth forecasts (1.4 per cent). The adjustment should then be on the 0.2 per cent difference between the two projections.

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[50] Frontier Economics, *Review of ACIL Tasman recommendations*, report prepared for CitiPower, June 2010, pp. 15-16.

[51] NIEIR, *Electrical sales and customer number forecasts to 2019 for the JEN electricity region, a report for Jemena Electricity Networks (Victoria),* June 2010, p. 6.

The additional energy use from the population growth adjustment should be 309 GWh for all Victorian distribution businesses, as opposed to the suggested additional 4,647 GWh as proposed by the AER.

NIEIR adds that population growth is a core model input which therefore should not be factored as a post model adjustment due to the consequential impacts on other modelling methods. The correct approach to factoring revised inputs is to adjust them in the core model so that the relational impacts are also considered in the overall forecasts.

JEN comments

While ACIL Tasman cite only three series of ABS population projections (A, B and C)[52] the ABS has in fact produced 72 different series.[53] Series A, B and C are merely reference points in the multitude of possible scenarios.

Given the numerous caveats that the ABS has made about its projections, and that they are not intended as predictions or forecasts, but illustrations of growth and change in the population that would occur if assumptions made about future demographic trends were to prevail, JEN submits that no one scenario can be singled out as preferable, as ACIL Tasman has done.

However, JEN agrees that it should revisit its economic assumptions (including population) and notes that NIEIR has done this. The results are summarised in section 5.5.1.

5.3.3 Economic growth

JEN notes that NIEIR has updated its Victorian GSP forecasts. The results are summarised in section 5.5.

5.3.4 MEPS for lighting

Frontier Economics comments[54]

ACIL Tasman recommends that the AER reduce the energy reduction attributed to the lighting MEPS so that it does not exceed the reduction forecast in the lighting MEPS RIS. In practice, this implies around a 13 per cent reduction in NIEIR's

52 ACIL Tasman, Victorian Electricity Distribution Price Review, *Review of electricity sales and customer numbers forecasts, Final report*, 11 May 2010, Table 1, p. 13.

53 ABS 3222.0 - Population Projections, Australia, 2006 to 2101 - released September 2008: Explanatory notes http://www.abs.gov.au/AUSSTATS/abs@.nsf/Latestproducts/3222.0Appendix12006%20to%202101?opendocument&tabname=Notes&prodno=3222.0&issue=2006%20to%202101&num=&view=

54 Frontier Economics, *Review of ACIL Tasman recommendations,* report prepared for CitiPower, June 2010, pp. 9-12.

forecast energy savings. Frontier Economics does not recommend this adjustment because ACIL Tasman only considers:

> *estimates from the lighting MEPS RIS* - Frontier Economics reviewed a wider range of sources in Frontier (2010)[55], and these suggest that the lighting MEPS RIS may underestimate the level of residential lighting use (and savings)
>
> *estimates for residential lighting, not commercial lighting* - a similar comparison indicates the lighting MEPS RIS estimates higher savings in commercial lighting energy than NIEIR. ACIL Tasman does not appear to take this into account.

Frontier Economics concludes that:

> Either way, NIEIR's estimate is considerably more conservative than implied by the RIS: in our view the RIS understates the potential savings from residential lighting but overstates the potential savings from commercial lighting. It is inconsistent to consider one but not the other, hence we believe that the ACIL Tasman recommendation, which only considers residential savings and relies entirely on the RIS estimates, should be rejected.[56]

NIEIR comments[57]

NIEIR's estimated market share mix of new bulbs purchased [now] suggests an average reduction in energy use of 65 per cent from replacement of incandescent lights, compared to the previously assumed 80 per cent efficiency.

NIEIR has also considered the inclusion of a rebound effect in lighting use, which implies that although savings in energy are achieved by each light bulb, the lighting comfort levels (lumens) sought after the efficiency improvement, sets off some of the implied saving. The rebound effect discounts the initial estimated savings, in the order of 10 per cent.

JEN comments

JEN fully concurs with Frontier Economics' assessment that the RIS offers a limited basis for estimating potential energy savings from lighting MEPS. Frontier Economics has provided very detailed comparisons of the RIS and alternative sources and analyses of MEPS savings in its two 'policy' reports (the review of NIEIR policy adjustments report section 3.3, and the review of ACIL Tasman's recommendations report section 2.4). JEN agrees with Frontier Economics conclusion that:

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55 Frontier Economics, *Review of policy adjustments*, report prepared for CitiPower, June 2010, section 3.3.

56 Frontier Economics, *Review of ACIL Tasman recommendations,* report prepared for CitiPower, June 2010, p. 12.

57 NIEIR, op. cit. pp. 3-4.

> The results show that the NIEIR estimates are reasonable and do not warrant discounting.[58]

5.3.5 Standby power

Frontier Economics comments[59]

There is sufficient evidence of policy action to meet a One Watt Standby Power target for appliances.

The National Standby Strategy is a 10-year plan (announced by the MCE in 2002) which has already seen the development of detailed product profiles which set out interim voluntary targets for standby power for 2007 and more stringent mandatory targets for 2012. Although the future mandatory targets have not been legislated, this should not be inperpreted as evidence of deviation from the original strategy. Legislation can be expected if voluntary action is inadequate. It is reasonable to conclude that the target will be met through either voluntary standards or, if required, mandatory targets.

ACIL Tasman acknowledge that some product MEPS already include a standby power target. This is supporting evidence for the argument that mandatory standby power targets will be introduced for other products.

NIEIR comments[60]

Despite the fact there is no actual policy set out by the Victorian Government, there is a national Government strategy:

> The Ministerial Council has resolved that Australia will expand its commitment to reducing excessive standby by formulating coordinated product-specific plans to address excessive standby over the next ten years, 2002–2012, within the umbrella of the IEA "One Watt" initiative. Within this timeframe, specific product types may be identified as "at risk" of using excessive standby and will therefore be targeted for specific action. Each product will then be dealt with in potentially a two-stage action plan designed to reduce standby to levels acceptable for that product as quickly as economically viable.[61]

This implies that appliances will eventually all receive product profiles as well as regulatory impact statements, guiding towards a one watt standby most likely as the strategy notes, through expanded MEPS for appliances.

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58 Frontier Economics, *Review of ACIL Tasman recommendations,* report prepared for CitiPower, June 2010, p. 11.

59 Frontier Economics, op. cit. p. v.

60 NIEIR, op. cit. p. 4.

61 MCE, *Australia's standby power strategy 2002–2012: an initiative of the Ministerial Council on Energy forming part of the national greenhouse strategy*, 2002, p. 7.

5.3.6 Insulation target

Frontier Economics comments[62]

The early cancellation of the Commonwealth Home Insulation Program (HIP) will reduce the estimated energy savings originally presented by NIEIR. Frontier Economics accounted for the early termination of the scheme in developing the revised estimates in Frontier (2010). This recognises the fact that at least 30 per cent of uninsulated homes had already received insulation under the scheme prior to its cancellation, and these homes will realise ongoing energy savings in the future which should be accounted for in the energy projections. In JEN's view, ACIL Tasman has not provided sufficient evidence to justify why these savings should be disregarded.

NIEIR comments[63]

It is unclear if insulation will be targeted again through new revised policy initiatives; therefore, the impact has mostly been withdrawn in NIEIR's forecast except for a small saving estimated for the coming winter, which will eventuate from the recent installations.

JEN comments

Cancellation of the home insulation program does not eliminate the energy savings that will result in the dwellings where insulation was installed. The program had extraordinary uptake in the short time it was in operation. The program started on 1 July 2009 and was terminated in February 2010. In that time, 1.1 million homes were insulated at a cost of $1.5 billion.[64] This is nearly 60 per cent of the ultimate target of 1.9 million homes.

JEN agrees with Frontier Economics that it is too early for the ultimate impact of the program to show up. JEN notes that Frontier Economics has estimated a small but significant annual effect of the home insulation program to 2015[65], whereas NIEIR, in its updated forecasts, has only allowed a one-off effect in 2010.

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62 Frontier Economics, op. cit. p. v.

63 NIEIR, op. cit. p. 5.

64 The Hon. Greg Combet AM, MP, Minister Assisting the Minister for Climate Change and Energy Efficiency, *Home Insulation Program*, Speech, 10 March 2010.

65 Frontier Economics, *Review of policy adjustments*, report prepared for CitiPower, June 2010, Table 2.

5.3.7 AMI Victoria (energy)

Frontier Economics comments[66]

The Moratorium

Frontier Economics states that it is not clear whether ACIL Tasman bases its recommendation to disregard the effect of AMI solely on the moratorium. ACIL Tasman does not make it clear what it would consider to be reasonable energy savings from AMI once the moratorium is lifted.

Frontier Economics believes that first, even if the moratorium is maintained for compulsory TOU tariffs, optional TOU tariffs are likely to be allowed as these are required to capture many of the purported benefits of AMI. Optional TOU tariffs should deliver the bulk of potential energy savings.

Secondly, some studies indicate that in-home displays (**IHDs**) which provide consumers with real-time information on energy use can deliver energy savings even in the absence of TOU tariffs. While IHDs are not mandatory as part of the AMI roll-out, the meters have the functionality to support IHDs and consumers most responsive to the information will be most likely install an IHD.

For these reasons, Frontier Economics does not believe that the moratorium should be used as a reason to completely disregard AMI energy savings.

Energy savings

Frontier Economics notes that ACIL Tasman does not present an alternative estimate of what it would consider as reasonable energy savings.

Frontier Economics is of the view that NIEIR's estimated savings from AMI (of 8 per cent) are overstated, and provide an alternative estimate of energy savings from AMI which it considers to be reasonable.[67] Its lower estimate takes into account many of ACIL Tasman's arguments. Frontier Economics reiterates that it does not believe it is reasonable to assume no energy savings from AMI.

Likely size of energy reduction

Frontier Economics's review of further studies on the assumed reduction of average energy use reveals considerable uncertainty regarding the potential benefits of AMI.

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66 Frontier Economics, *Review of ACIL Tasman recommendations,* report prepared for CitiPower, June 2010, p. 4.

67 Frontier Economics, *Review of policy adjustments*, Report prepared for CitiPower, June 2010, Section 3.2.5, especially pp. 25-26.

Compared to NIEIR, other more robust and comprehensive studies proffer alternative conclusions that in Frontier Economics's view are based on more realistic and relevant assumptions.

The wide range of figures reflects a range of different approaches and assumptions. The Ministerial Council on Energy (**MCE**) assumptions are generally reasonable with regard to take-up rates and tariffs, and NERA includes a high demand response scenario to account for higher elasticity of demand in Australia than in California. However, the application of take-up rates to discount energy savings is likely to understate the potential energy savings:

- Firstly, it is likely that a minority of customers will deliver the majority of energy savings, and these customers will be more likely to take-up TOU tariffs. As such, the conservation effect should not be discounted linearly as per the MCE studies.

- Secondly, savings from the feedback effect based on real-time information from IHDs should not be discounted in line with take-up of TOU tariffs.

Given Frontier Economics' concerns with the application of the MCE estimates, it does not consider that these estimates should be directly applied. Frontier Economics recommend adopting a range within the estimates proposed by the DECC[68] and Frontier Economics UK (1 per cent to 4 per cent), with a midpoint of 2.5 per cent. This is consistent with the MCE high-demand response scenario if it could be corrected for the discounting of savings in line with take-up rates.

NIEIR and the MCE assume that potential commercial energy savings in response to AMI are likely to be smaller than residential savings. Frontier Economics considers this approach reasonable, and therefore assume commercial energy savings of 0.5 per cent (20 per cent of the residential saving, in accordance with NIEIR).

NIEIR comments

In estimating the impact for Victoria, NIEIR is taking the conservative view. NIEIR forecasts a 4 per cent reduction in residential energy demand for Victoria due to AIMRO.[69]

JEN comments

JEN supports Frontier Economics' view that TOU pricing will be implemented over the next regulatory period which will reduce energy consumption and peak demand. This is in contrast to the ACIL Tasman and AER views that no impacts

[68] Department of Energy and Climate Change (UK).

[69] NIEIR, op. cit. p. 74.

should be taken into account in the forecasts. Frontier Economics believes that a range of 1 to 4 per cent impact on energy demand from TOU pricing is realistic and recommend a midpoint of 2.5 per cent. Although NIEIR's modelling falls within this range, it is at the higher end of expectations, JEN has accepted Frontier Economics' estimate of a 2.5 per cent saving in energy consumption when TOU pricing is introduced.

JEN notes that NIEIR has assumed that, following the roll-out of meters, TOU pricing will be introduced by retailers in 2012.[70]

5.3.8 AMI Victoria (maximum demand)

NIEIR comments

The NIEIR reports for JEN include a table 6.15 which summarises the percentage impact on maximum demand based on overseas studies.[71] NIEIR states that:

- the empirical results presented in Table 6.15 are informative, but in most cases vastly over-state the potential impact on Victoria's peak demand
- it has assumed that the percentage reduction in peak demands would be 2 per cent. This reduction is consistent with the minimum impacts reported in Table 6.15 under time-of-use pricing.

JEN comments

While JEN has accepted Frontier Economics' mid-point estimate for energy savings in place of NIEIR's estimate, JEN considers that it is unnecessary to estimate a revised AMI impact for its maximum demand forecast.

Given that NIEIR already has a relatively low estimated impact of 2 per cent, any adjustment would not be material and would essentially only slightly increase the maximum demand. Such an adjustment would not result in any material change in the capex forecasts in JEN's revised regulatory proposal.

Further, while it is relatively easy to adjust the NIEIR energy forecasts for revised AMI energy savings (since the adjustment is a known figure), adjusting maximum demand would require a number of assumptions to be made. Given the likely immateriality of the adjustment, JEN submits that the updated NIER forecast for maximum demand (which already reflects a wide range of other policy adjustments) meets the requirements of the Rules.

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70 Ibid.

71 NIEIR, op. cit. p. 56 (energy sales and customers report).

5.3.9 Maximum demand starting point

JEN believes that the same rationale which Frontier Economics applied to ACIL Tasman's recommendations for energy impacts would apply equally to maximum demand – i.e. it would not be reasonable to entirely discard any maximum demand adjustment due to AMI.

With respect to maximum demand, JEN has accepted the revised NIEIR maximum demand forecast without adjustment.

The revised NIEIR maximum demand forecast is higher than the November 2009 forecast due to a revised assessment of air conditioning installations, and the recognition by NIEIR of the distribution outages in January 2009. As a result, there is minimal change to JEN's forecast zone substation non-coincident maximum demand submitted in November 2009, with the 2015 maximum demand forecast being 1,212.7 MW, compared with 1,208.6 MW previously.

5.3.10 Zone substation forecasts for JEN (maximum demand)

JEN does not use a single diversity factor to aggregate zone substation non-coincident maximum demand into system level demand. Details of JEN's load forecasting methodology can be found in the document 'Jemena Electricity Networks - Load Demand Forecast Methodology' submitted as an attachment to JEN's response to AER demand forecasting questions dated 25 January 2010 (see Appendix 5.10).[72]

JEN agrees, however, that the diversity factor should not be diverging from its historical value. The average diversity factor quoted by ACIL Tasman is based on historic maximum demands that have not been temperature corrected. When the historic demands are corrected to 50 per cent POE, the observed diversity factor should not show a diverging trend between historical and forecast.

JAM (on behalf of JEN) has carried out a full reconciliation of its bottom-up forecast of zone substation coincident and non-coincident maximum demand with NIEIR's revised system level forecast (see Appendix 5.9). JEN has demonstrated that the diversity factor is fairly constant between historic and forecast demand, as shown in Appendix 5.9.

5.4 Review and update by NIEIR

As noted in section 5.3, JEN engaged NIEIR to review and update the assumptions previously used in its November 2009 forecasts, to re-run its forecasting model and to update its forecasts where necessary. The revised forecasts are included in updated NIEIR reports included in this revised regulatory proposal as Appendix 5.2

[72] JEN's response and attachment were emailed to the AER on 5 February 2010.

(sales and customer number forecasts) and Appendix 5.3 (maximum summer demand forecasts).

NIEIR has advised JEN that it has:

- updated all of the economic drivers, including revised state GSP and population forecasts
- delayed the introduction of the CPRS until 2013
- updated the actual (historical) values for JEN customer numbers, maximum demand and energy consumption
- revised a number of policy impacts on the forecasts, the main adjustments being:
  - modifying MEPS for lighting (see section 5.3.4)
  - scaling back the insulation impact (see section 5.3.6)
  - revising photovoltaic installations given new data
  - updating air conditioning sales forecasts slightly affecting MEPS for air conditioning and for the record airconditioning sales in 2009
  - revising downwards electric car penetration
  - revising the energy impacts associated with residential building standards
  - assessing potential rebound effects in various policies.

The updated policy assumptions reflect more recent information that has become available to NIEIR since the preparation of the November 2009 forecasts. In some cases, this has resulted in adjustments to policy assumptions that were accepted by the AER in its draft decision (such as photovoltaics, air conditioning and residential building standards).

Although some of these adjustments are not a direct response to matters raised in the draft decision, they are all required to appropriately address matters raised in the draft decision.[73]

[73] Clause 6.10.3 of the Rules allows a DNSP to make revisions necessary so as to incorporate the substance of any changes required to address matters raised by the draft distribution determination or the AER's reasons for it.

JEN notes that one reason for the AER's rejection of the NIEIR growth forecasts in the draft decision was a concern that many of the input assumptions were outdated.[74] Therefore, to the extent that NIEIR's adjustment of these policy assumptions is an update for more recent information, this is required to address the matter of forecast currency raised in the draft decision.

More fundamentally, it is only prudent for NIEIR to revisit its forecasts in totality in light of the AER's conclusions in its draft decision. The NIEIR model is a highly sophisticated model with many complex inter-relationships between the various inputs and assumptions. Therefore, the adjustment of one input or assumption necessarily requires a review of the model in its totality and potentially the adjustment of other related inputs. The NIEIR model cannot simply be adjusted for those policy assumptions that were specifically rejected by the AER whilst ignoring all others. To do so would potentially bias the forecasts one way or the other.

5.5 Results of NIEIR update

5.5.1 Economic (GSP and population)

NIEIR has produced revised growth scenarios for Australia and VIC. NIEIR has also produced revised population growth estimates for Victoria, also shown in Table 5-3.

Table 5-3: NIEIR revisions to growth of Australian Gross Domestic Product, Victoria Gross State Product and Victorian population (per cent per year)

NIEIR projections	2010	2011	2012	2013	2014	2015	Average (a)
Australia GDP							
November 2009	1.2	2.2	4.6	2.8	1.7	1.8	2.4
June 2010	2.4	3.4	3.8	2.6	1.7	2.5	2.7
VIC GSP							
November 2009	1.2	2.2	4.4	2	0.2	0	1.7
June 2010	3.1	3.6	3.3	2	1.5	1.9	2.6
VIC population							
November 2009	1.5	1.3	1.2	1.1	1.2	1.2	1.3
June 2010	2	1.7	1.5	1.4	1.3	1.3	1.5

(a) These are simple averages – compound growth would be slightly lower over the period.

74 Draft decision, p. 156.

NIEIR has forecast stronger Victorian GSP growth over 2010-2015, reflecting revised near-term and medium-term outlooks. NIER's average annual GSP growth over the period of 2.6 per cent exceeds the comparable forecast of KPMG Econtech (cited by ACIL Tasman) who have forecast an average of 2.2 per cent in its medium scenario.[75]

NIEIR's average annual population growth over 2010-2015 of 1.5 per cent (at a minimum) meets ACIL Tasman's recommendation to use the ABS Series B growth of 1.4 per cent.[76]

All electricity quantity forecasts have been weather normalised, as described in section 5 of the latest NIEIR reports.

5.6 JEN adjustments to NIEIR forecasts

As noted in section 5.3.7, JEN has accepted Frontier Economics' estimate of a 2.5 per cent saving in energy consumption when TOU pricing is introduced in contrast to NIEIR's assumption of 4 per cent. Therefore, JEN has had to adjust (upwards) the NIEIR energy forecasts for the difference between the two estimates.

This adjustment is shown in Appendix 5.8. The basic steps have been to:

- obtain the 4 per cent AMI impact assumed by NIEIR for both residential and commercial over 2012-2019 (390.83 GWh)
- calculate a total AMI impact of 2.5 per cent for the same period (244.27 GWh)[77]
- allocate the 244.27 GWh to each year of the forecast period in the same proportion as shown in NIEIR's original forecast
- split the allocated annual total quantities into residential and commercial using the same per cent split in NIEIR's forcast (approximately an 83 per cent to 17 per cent annual split)
- deduct the calculated 2.5 per cent savings for residential, commercial and total energy from NIEIR's original forecasts to obtain the annual adjustments necessary to NIEIR's forecasts.[78]

75 ACIL Tasman, op. cit., p. 18.

76 ACIL Tasman, op. cit., p. 15.

77 Calculated as 390.83 GWh divided by 4 per cent then multiplied by 2.5 per cent.

78 A total of 146.56 GWh over 2012-2019.

Having obtained the adjustments necessary to NIEIR's total residential and commercial energy, JEN then split these totals into its residential and small business tariff classes (except unmetered supply tariff), using the same per cent allocation as shown in NIEIR's tariff forecasts for 2011.

5.7 Other demand issues

5.7.1 Comparison of AEMO/VENCorp 2009 forecasts with distribution business forecasts

The AER draft decision compared the 2009 VENCorp forecast with the NIEIR Victorian distribution business forecasts as follows:

> The Victorian DNSPs' forecasts are significantly different from those published in VENCorp's 2009 APR, released in April 2009. VENCorp forecasts an average growth in Victorian energy consumption of 0.9 per cent per year over 2011–15 (medium growth, 50 per cent PoE scenario). The Victorian DNSPs' forecasts predict an average decline in energy sales of –0.7 per cent per annum over the same period.[79]

The draft decision further noted that VENCorp's 2009 APR forecasts:

- contain the same list of policy adjustments used by NIEIR
- were conducted at the height of the GFC and therefore are based on a different set of economic growth assumptions.[80]

NIER has demonstrated that this comparison is not valid for a number of reasons.[81]

The VENCorp forecast was based NEMMCO's economic profiles prepared in April 2009 when there was considerable uncertainty regarding the Global Financial Crisis. NEMMCO's consultant had Victorian GSP at nearly three per cent over the 2011 to 2015 period. The NIEIR forecast was around one percent lower than this and this explains a major part of the large divergence in the energy forecasts.

The VENCorp forecasts include direct transmission customers. Assumed load reductions or changes in 2009-10, 2010-11, and 2014-15 by these customers had a significant impact on VENCorp's energy growth rates.

Further, the policy assumptions used for AEMO/VENCorp and the Victorian DB's were different, particularly AMI pricing impacts. In addition, the VENCorp forecasts excluded any commercial policy impacts.

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79 Draft decision, p. 82.

80 Draft decision, pp. 82-3.

81 NIEIR, op. cit. p. 8.

Based on the above analysis, NIEIR has concluded that the AER draft decision for energy sales is not consistent with the VENCorp 2009 forecast.

5.8 JEN's revised regulatory proposal

Table 5-4 shows JEN's revised growth forecasts based on NIEIR's updated forecast amended for the AMI TOU pricing impact in accordance with section 5.6.

Table 5-4: Revised JEN total electricity forecast 2010 to 2015

Details	Forecast year ending					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Maximum demand (MW)						
NIEIR system forecast for maximum summer demand (50% POE)	957.8	989.0	1,017.8	1,047.7	1,075.9	1,094.9
JEN system forecast for maximum summer demand - bottom up method (50% POE)	957.8	989.0	1,017.8	1,047.7	1,075.9	1,094.9
Customer numbers						
Residential[82]	279,107	284,657	289,774	294,207	298,180	302,453
Small business	26,883	27,330	27,666	27,780	27,837	28,048
Large business	1,178	1,178	1,177	1,174	1,170	1,169
Total customer numbers	**307,168**	**313,164**	**318,616**	**323,161**	**327,188**	**331,669**
Energy consumption (GWh)						

[82] Residential numbers exclude off-peak meters.

Details	Forecast year ending					
	2010	2011	2012	2013	2014	2015
Residential	1,282	1,285	1,275	1,253	1,235	1,228
Small business	797	812	821	821	821	827
Large business[83]	2,220	2,180	2,163	2,126	2,091	2,073
Total business	3,017	2,992	2,984	2,947	2,912	2,900
Unmetered (including Public lighting)	55	54	54	53	53	52
Total energy consumption	**4,353**	**4,331**	**4,312**	**4,254**	**4,200**	**4,181**
Peak and off-peak energy (GWh)						
Peak energy	3,049	3,044	3,030	2,987	2,948	2,934
0ff-peak energy	1,304	1,287	1,282	1,267	1,252	1,246
Total energy	**4,353**	**4,331**	**4,312**	**4,254**	**4,200**	**4,181**

5.9 Compliance with the Rules

JEN believes that its revised demand forecasts are a realistic expectation of the demand forecast required to achieve the operating and capital expenditure forecasts required by clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the Rules.

JEN's revised demand forecasts achieve a realistic expectation of the demand forecast because:

- it has relied on NIEIR to complete its forecasts, noting that Frontier economics has endorsed NIEIR's methodology (as did ACIL Tasman and the AER in its draft decision) and to Frontier Economics' knowledge "no other model in Australia has similar capabilities" (see Appendices 5.4 and 5.5)

[83] Large business includes traction.

- the policy adjustments, including a TOU pricing impact on energy consumption, made by NIEIR and JEN reflect the best available information at the time JEN makes this regulatory proposal. Appendices 5.6 and 5.7 provide the justification for NIEIR's and JEN's policy adjustments

- the assumptions used by NIEIR are superior to the alternatives proposed by ACIL Tasman and accepted by the AER. JEN notes that several of the ACIL Tasman proposed adjustments are subjective or based on questionable analysis (see Appendices 5.6 and 5.7).

Overall, JEN believes that the revised NIEIR demand forecasts with the additional supporting Frontier Economics reports demonstrate that the revised NIEIR demand forecasts reflect the realistic expectations of future energy consumption and peak demand better than the requirements of the AER's draft decision and its consultants, ACIL Tasman.

6 Outsourcing and related party transactions

- The price JEN is contracted to pay JAM under the AMA is consistent with clauses 6.5.6(c) and 6.5.7(c) of the Rules and allows the total contract price (that is, the contract price inclusive of margins and overheads) to be used as the basis for JEN's operating and capital expenditure and in the EBSS.

- To draw this conclusion, JEN has examined the AER's proposed assessment framework for outsourcing contracts, including its 'presumption threshold'. JEN has also examined the AER's assessment of JEN's outsourcing arrangements.

- The AER's proposed treatment of outsourcing contracts that fail its presumption threshold, and the basis upon which it has developed this aspect of the framework, have a number of fundamental shortcomings and is inconsistent with the original intent of clauses 6.5.6(c)(2) and 6.5.7(c)(2), prior regulatory decisions by the AER, the ESCV and the Tribunal. The AER's assessment framework is also inconsistent with other aspects of the AER's draft determination and other provisions in the Rules and the NEL more generally.

- One of the more fundamental shortcomings with the AER's framework for assessing outsourcing contracts is that it fails to recognise the potential for an outsourcing contract between related parties to deliver a prudent and efficient outcome. This is because the AER's assessment framework assumes unreasonably that the DNSP will be able to access the same economies of scale, scope and other efficiencies that would be available to a contractor that provides services to any number of related and unrelated parties.

- The practical effect of this assumption is that an outsourcing contract that is deemed to fail the presumption threshold will never be viewed as a more efficient means of delivering a service than the DNSP providing the services in-house. As a consequence, DNSPs will have a perverse incentive to provide services in-house that could otherwise be provided at lower cost through outsourcing. The AER in effect sets up a test that a related-party contract can never pass.

- In view of the deficiencies with the AER's proposed framework and the broader inconsistency with the NEO and a number of revenue and pricing principles, JEN has proposed a number of modifications be made to the

AER's framework. These modifications are designed to ensure that, if an arrangement does not meet the presumption threshold, a proper and more detailed inquiry is undertaken to determine whether the price under the contract represents a prudent and efficient outcome or is a price which has been 'artificially inflated.'

- Using this modified framework, JEN has examined its own outsourcing arrangements. In short, the results of this assessment indicate that:

  - the total contract price payable under JEN's principal outsourcing contract, the AMA (inclusive of overheads and margins), is lower than the costs that would be incurred if JEN was to provide the services in-house

  - opex benchmarking undertaken by the UMS Group reveals that on a variety of performance measures, JEN's operating expenditure is efficient relative to the industry average while the AER's capex benchmarking indicates that JEN's historic capital expenditure (including the margin payable to JAM) has been efficient relative to the industry average

  - the non-price terms and conditions are consistent with (or in fact superior to) those that would be negotiated by parties operating on an arm's length basis

  - the contract provides the contractor with strong and ongoing incentives to pursue efficiencies and to pass these back to JEN and in turn to users.

JEN's operating and capital expenditure forecasts for the 2011-2015 regulatory control period have been developed having regard to the following two arrangements:

- the AMA (and its predecessor, the Letter Agreement), which provides for the supply of asset management services, operating and maintenance services and routine and non-routine capital works by JAM to JEN

- the Enterprise Support Function (**ESF**) arrangement, which provides for the supply of corporate services by Jemena Limited to JEN.

The AER's assessment of these two arrangements has been undertaken using its proposed framework for assessing outsourcing arrangements. A description of the assessment framework is contained in Chapter 6 of the draft decision while the application of this framework to JEN's outsourcing arrangements is set out in section 6.6.2 and Appendix H.3.

6.1 Summary of JEN's original regulatory proposal

For its original regulatory proposal, JEN forecast the outsourced costs it will incur through its AMA with JAM inclusive of the {c-i-c} commercial margin payable to JAM under that agreement.

JEN also forecast its costs inclusive of allocations of corporate costs that JEN incurs from Jemena Limited and that JAM incurs when providing services to JEN. These were considered in JEN's opex and capex forecasts.

JEN's original proposal demonstrated the prudency and efficiency of its outsourcing arrangements by providing details of the AMA including the cost, incentive and service performance provisions of this agreement. JEN also provided extensive benchmarking studies which demonstrated that the margin payable under the AMA was comparable with equivalent industry margins.

6.2 Summary of AER's draft determination and decision

The AER's draft determination proposed not to allow within JEN's forecast operating and capital expenditure the commercial margin and certain corporate costs that JEN is contracted to pay JAM under their AMA. It also excluded certain corporate costs incurred by JEN.

The AER draft decision sets out:

- the framework that it proposes to employ when assessing outsourcing arrangements entered into by DNSPs
- the AER's application of this framework to JEN
- other matters to which the AER has had regard.

6.2.1 AER's proposed assessment framework

Chapter 6 of the AER's draft decision sets out the framework that it proposes to employ when assessing outsourcing arrangements entered into by DNSPs. The proposed framework, as illustrated in Figure 6-1, consists of a two stage inquiry process that involves:

- distinguishing between those contracts entered into by a DNSP that can be *presumed* to 'reflect efficient costs and costs that would be incurred by a prudent operator' and those that cannot

- undertaking a more detailed review of the contracts to determine whether the contract price, the contractor's costs or some measure in between these two would be consistent with the forecast operating and capital expenditure criteria specified in clauses 6.5.6(c) and 6.5.7(c) of the Rules.

The first of these stages, referred to as the presumption threshold, requires consideration in the first instance to be given to whether, by virtue of the relationship between the DNSP and the contractor or the circumstances in which the contract was negotiated, the DNSP may have had an *incentive* to agree to pay an 'artificially inflated' price, or otherwise agree to non-arm's length terms.[84]

Where a DNSP is found to have had *no* incentive to enter into such an arrangement, the contract price will be *presumed* to be consistent with the forecast operating and capital expenditure criteria of the Rules.[85] In those circumstances where a DNSP is found to have had an incentive to agree to non-arm's length terms, the contract may still pass the presumption threshold if it was entered into following a 'competitive open tender process conducted in a competitive market'.[86] Where the contract was not the subject of such a process, the contract will be deemed to *fail* the presumption threshold.[87]

The second stage of the AER's framework requires a more detailed review of contracts that both pass and fail the presumption threshold to determine whether the contract price, an adjusted contract price or the contractor's costs should be used as the basis for determining forecast operating and capital expenditure.

For those contracts that are deemed to pass the presumption threshold, the *contract price* will form the basis for determining forecast operating and capital expenditure, subject to the caveat that all of the services provided under the contract are required in the delivery of the relevant service and the price does not give rise to any 'double-counting' of costs or risks.[88]

84 Draft decision, pp. 170-2.

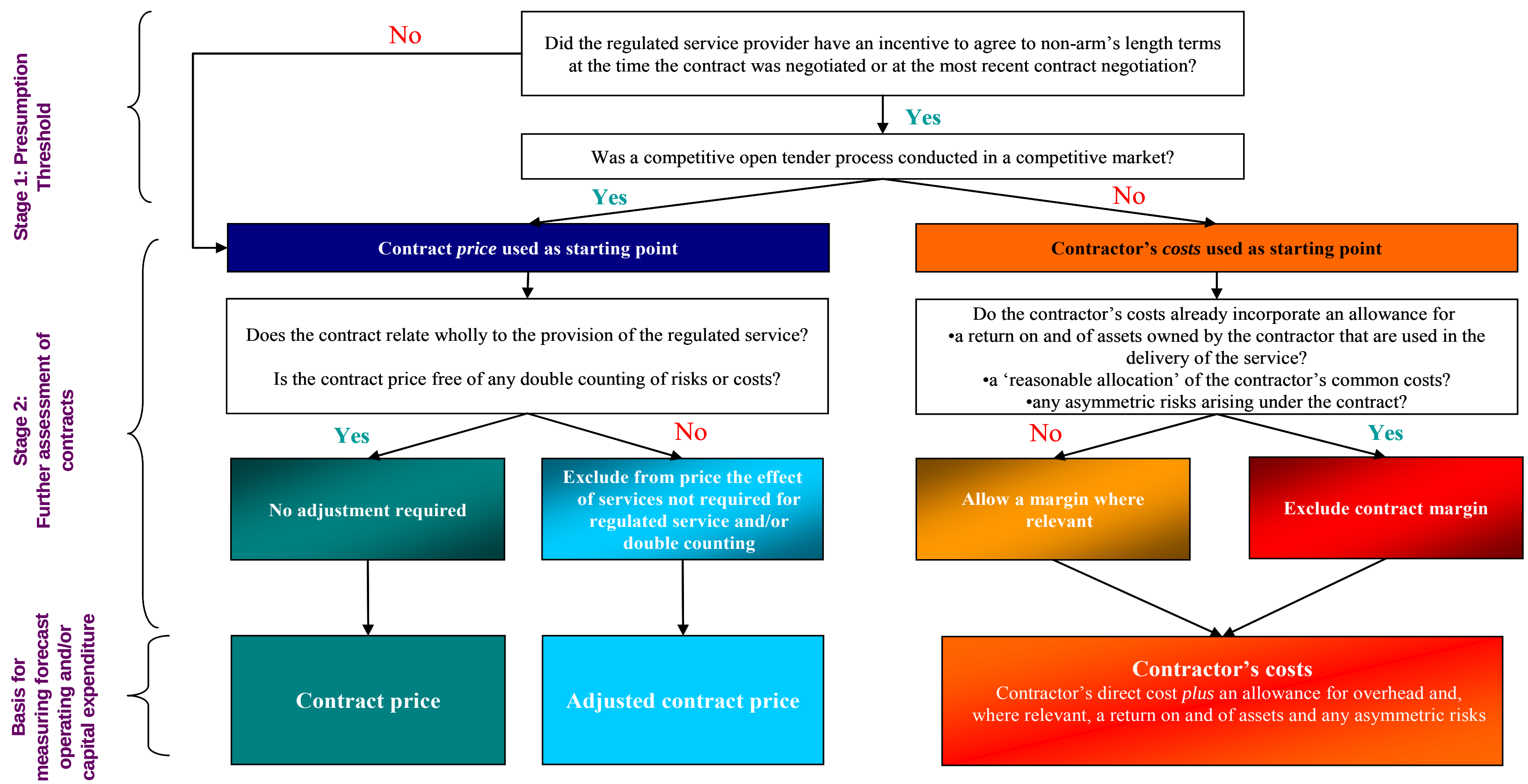
85 Draft decision, p. 174.

86 Draft decision, p. 170.

87 Draft decision, pp. 170-4.

88 Draft decision, pp. 174-6.

Figure 6-1: AER's Proposed Framework



Source: Chapter 6 of AER draft decision.

For those contracts that are deemed to fail the presumption threshold, the AER's framework requires the *contractor's actual costs* to be used as the starting point for determining forecast operating and capital expenditure with consideration then given to whether there are any 'legitimate reasons to justify a margin above these costs'.[89] Those factors that have been identified by the AER as being 'legitimate' and therefore warranting the payment of an amount in excess of the contractor's directly incurred costs include:[90]

- the allowance required to enable the contractor to recover a 'reasonable allocation' of its common costs
- the return on and of capital required to compensate the contractor for the use of physical assets employed in the provision of services that do not form part of the DNSP's RAB
- the allowance required by the contractor to self insure against asymmetric risks arising under the contract provided that it does not give rise to any double counting across other aspects of the DNSP's building block proposal.

The AER's proposed treatment of contracts that fail the presumption threshold is similar in nature to the approach that was employed by the ESCV in the context of the 2006-2010 EDPR[91] but markedly different from the approach employed by the ESCV two years later in the 2008-2012 Gas Access Arrangement Review (GAAR).[92] Between these two reviews, the ESCV's framework for assessing outsourcing arrangements underwent a number of fundamental changes. Perhaps the most significant change to occur between these reviews was the ESCV's acknowledgment that while a contract may not be able to be presumed to be efficient, the contract could still be efficient if the price paid under the contract was *less than or equal to* the costs that would be incurred if the services were provided in-house.[93] It was this acknowledgment that prompted the ESCV in its 2008-2012 GAAR to modify the framework used to modify the framework used in the 2006-2010 EDPR framework and to require contracts that failed the presumption threshold to be subject to an in-house cost versus contract price test (see figure below).

89 Draft decision, p. 177.

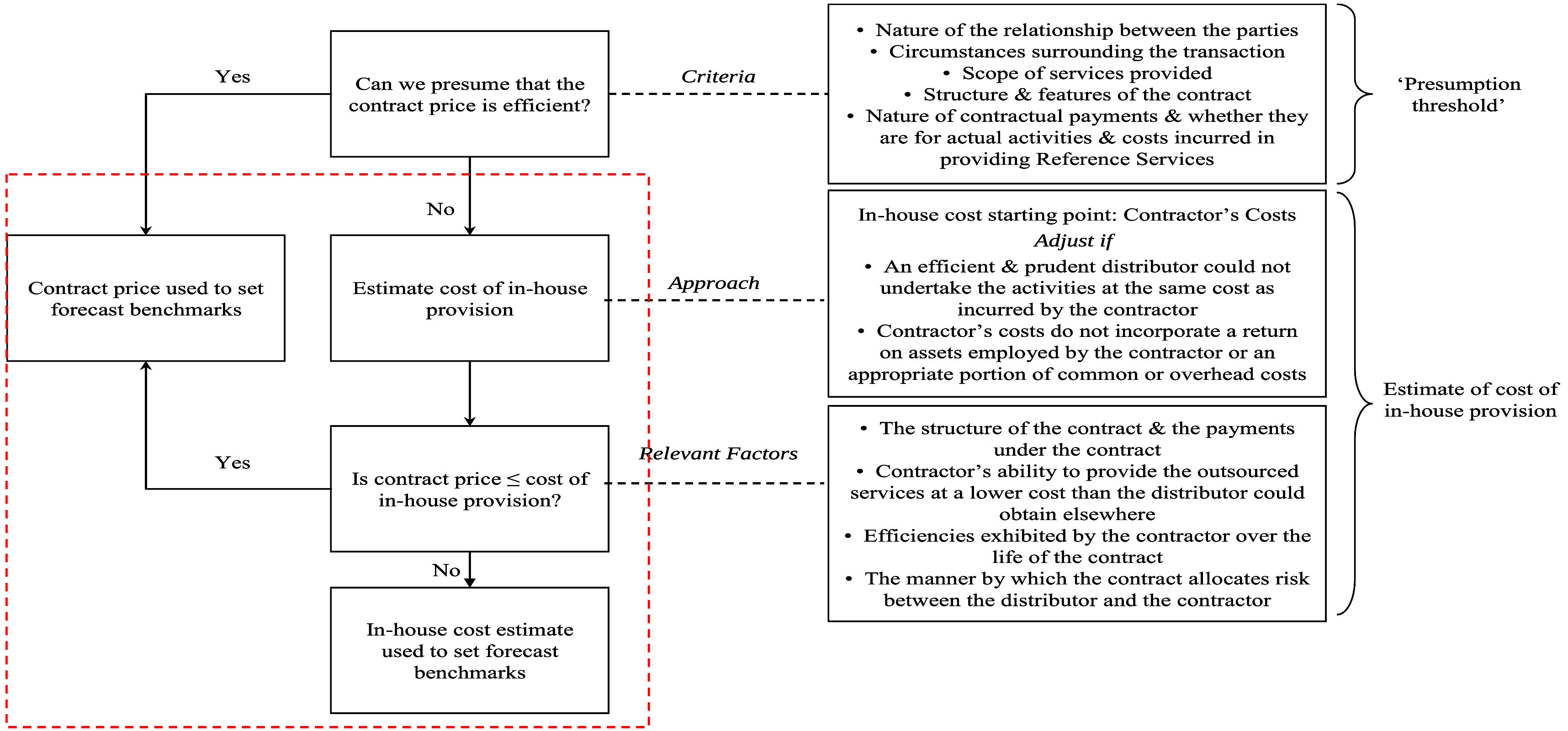
90 Draft decision, pp. 180-2, 186.

91 ESC, *Electricity Distribution Price Review 2006-10 Final Decision: Notice of Errata*, 23 November 2005.

92 ESC, *2008-2012 Gas Access Arrangement Review Final Decision*, March 2008, pp. 43-153 and ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, pp. 39-91.

93 ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 55.

Figure 6-2: Framework applied by the ESCV in the 2008-2012 GAAR



Source: NERA, *Treatment of Outsourcing Arrangements – Multinet Gas Distribution Partnership,* October 2007, p. v.

Rather than requiring a detailed ground up estimate of the cost of in-house provision, the ESCV's framework required the actual costs incurred by the contractor to be used as the starting point for the assessment of the cost of providing the services in-house. In doing so, the ESCV noted that it was *not* adopting the position that such costs formed a reasonable final benchmark of prudent and efficient costs for in-house provision. Rather, the ESCV explicitly acknowledged that if an outsourcing contract was expected to reduce costs relative to the cost of in-house provision, the full contract price should represent the appropriate cost benchmark:[94]

> In looking at the actual costs incurred by the contractor in undertaking the contracted activities, the Commission is not adopting the position that only the contractor's actual costs form a reasonable basis for the benchmark of prudent and efficient costs. The Commission accepts that, consistent with the views of both NERA and ACG, if over the relevant time horizon, the contractor incurs lower expected costs relative to providing the services in-house then this is a prudent and efficient outcome. Provided the overall contract payments do not exceed the amount that would have been incurred by the distributor undertaking the activity itself, the full contract amount would represent an efficient level of expenditure.

The costs the ESCV considered relevant to add to the contractor's direct costs included:

- a return on and of the assets employed by the contractor[95]
- an appropriate portion of common costs[96]
- an allowance for economies of scale, scope and other efficiencies (such as 'know-how') *not* otherwise available to the in-house provider.[97]

Comparing this list with the 'legitimate' factors identified by the AER, it is apparent that the principal difference between the two lies in their treatment of economies of scale, scope and other efficiencies. That is, while the ESCV recognised the importance of considering whether a regulated service provider would be able to access the same efficiencies available to the contractor, the AER has dismissed the need to do so on the basis of both:

- an hypothesis that in a workably competitive market contractors would not, in the long run, be able to charge a margin above its 'full economic costs and

[94] ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 55.

[95] ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 54.

[96] ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 54.

[97] ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 52.

earn abnormal profits due to the efficiencies available to the contractor that are not currently available to the service provider or other contractors'[98]

- the phrase *'in the circumstances of the relevant DNSP'* in the prudency criterion specified in clauses 6.5.6(c)(2) and 6.5.7(c)(2) of the Rules, which the AER has interpreted as requiring it to have regard to the DNSP's ownership structure and the efficiencies that would be available to the group to which the DNSP belongs rather than those that would be available to a 'hypothetical' DNSP operating on a stand alone basis:[99]

> It appears reasonable to conclude that the 'circumstances' of the DNSP includes its ownership structure, and in particular whether or not it is part of a large group of networks giving it access to economies of scale, scope and other efficiencies that wouldn't be available to a hypothetical 'standalone' network.
>
> …
>
> Accordingly, a 'standalone' cost standard would only appear appropriate in that reflects the circumstances under which the service provider is found in. However, where a service provider is part of a larger corporate group that owns and operates multiple networks, then these are the circumstances that service provider is found in, and accordingly this fact is important in assessing the costs that would be incurred by a prudent operator in the circumstances of that DNSP.
>
> Following on from this, the AER does not consider that economies of scale or scope or other efficiencies (for example, 'know-how') are a legitimate reason for a related party contractor to charge the service provider above its direct and indirect costs, as this approach would prevent consumers from sharing in these benefits.

In contrast to the position taken by the ESC, the AER has assumed that any economies of scale, scope or other efficiencies available to the contractor, including those derived from the provision of services to third parties and other entities in which the DNSP's owner only has a minority or no interest, will also be available to the DNSP.

The practical effect of this assumption is that an outsourcing contract that is deemed to fail the presumption threshold can never be a more efficient means of delivering a service than the DNSP providing the services in-house. That is, the AER sets up a test that an outsourcing contract, such as that between JEN and JAM, can never meet.

98 Draft decision, p. 182.

99 Draft decision, p. 179.

Implications for other aspects of the regulatory regime

The AER's proposed treatment of outsourcing contracts that both pass and fail the presumption threshold has implications for a number of other aspects of the regulatory regime such as the operation of the EBSS and the regulatory asset base (RAB) roll forward calculation.

Under the AER's proposed approach the actual operating expenditure measure used in the EBSS will be based on:[100]

- the contract price where the contract *passes* the presumption threshold
- the contractor's costs in those cases where the contract *fails* the presumption threshold.

While the AER considered applying the same approach to the calculation of the RAB roll forward, it concluded that the rules in their current form would prevent it from making such an adjustment. The margin payable under contracts that both pass and fail the presumption threshold have therefore been *retained* in the RAB roll forward calculation.[101]

6.2.2 AER's assessment of JEN's arrangements

The AER's assessment of JEN's outsourcing arrangements focused upon the AMA (and its predecessor the Letter Agreement) and the ESF. A summary of the AER's findings on these two agreements is set out below.

Asset management agreement

The application of the first stage of the AER's proposed framework to the AMA (and its predecessor, the Letter Agreement) led the AER to conclude that the contract could not be presumed to be efficient because:[102]

- at the time the contract was entered into JEN and JAM were jointly owned by SPI (Australia) Assets
- the AMA was not the subject of a competitive tender.

JAM's costs were therefore used as the starting point for the second stage of the AER's proposed framework and consideration was then given to whether any additional margin would be required to enable JAM to recover:

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[100] Draft decision, p. 190.

[101] Draft decision, pp. 188-190.

[102] Draft decision, Appendix H, pp. 14-15.

- *a reasonable proportion of is common costs* — Since an allowance had already been made in JAM's costs for a share of its overheads, the AER concluded that no additional margin was required for this aspect.[103] Based on its assessment of the allowance that had been made for overheads, the AER concluded that a reduction would be required to remove the effect of management fees and other finance/investment analysis/energy investment costs, which the AER claimed were 'strategic in nature' and did not relate to the provision of the distribution services[104]

- *a return on and of physical assets owned by JAM* — No allowance was made for this aspect in the AER's draft decision although the AER did leave open the potential for providing an allowance if JEN could demonstrate that JAM did utilise assets that did not form part of JEN's RAB.[105]

Having established that JAM's costs already included an allowance for overheads and that no allowance was required for a return on or of assets, the AER concluded that the margin payable under the AMA should be *excluded* from both:

- the calculation of JEN's forecast operating and capital expenditure for the 2011-2015 regulatory control period

- the EBSS calculations for the 2011-2015 regulatory control period.

Enterprise support function

In a similar manner to the AMA, the ESF arrangement between JEN and Jemena Limited was found by the AER to fail the presumption threshold.[106] Since there is no margin payable under this agreement, the AER's consideration of this arrangement focused upon whether the quantum of overheads allocated to JEN was reasonable. Just as it did with the AMA, the AER concluded that the overheads allocated to JEN should exclude the effect of management fees and other finance/investment analysis/energy investment costs.[107]

6.3 JEN's response to AER's draft determination and decision

JEN considers that the AER's proposed treatment of contracts that fail the presumption threshold has fundamental shortcomings and is inconsistent with the prior regulatory decisions and with other aspects of the draft determination.

[103] Draft decision, Appendix H, p. 15.

[104] Draft decision, pp. 199-208.

[105] Draft decision, Appendix H, pp. 37-38.

[106] Draft decision, Appendix H, pp. 18-19.

[107] Draft decision, p. 201.

Key elements of the AER's framework mean that an outsourcing contract that is deemed to fail the presumption threshold will never be viewed as a more efficient means of delivering a service than the DNSP providing the services in-house. As a consequence, owners of DNSP businesses will have substantially less incentive to establish and operate competitive asset management businesses that provide services to related and unrelated DNSPs even though they can provide services at lower cost than the DNSPs would otherwise be able to achieve.

That is, the AER has set up a test that an outsourcing contract, such as that between JEN and JAM, can never meet. This gives rise to perverse incentives for service providers to put in place arrangements that meet the AER's presumptive threshold, including:

- providing JEN with an incentive to contract with unrelated parties regardless of whether contracting with a related party would be more efficient
- assuming it even had the capability to do so, providing JEN with an incentive to build the capacity to provide the currently outsourced services in-house regardless of the likely inefficiencies this would give rise to, which would include the costs associated with building these capabilities in-house and the loss of economies of scope and scale as a consequence of JEN simply providing the relevant activities to itself.

It simply cannot have been the intent of clauses 6.5.6 and 6.5.7 to remove potentially prudent and highly efficient options available to service providers in making decisions as to how to structure their operations. To the extent the AER's assessment framework operates in this way, it is clearly inconsistent with the Rules and the Law.

JEN proposes modifications to the AER's framework. These help ensure that a more detailed inquiry is undertaken to determine whether the price under the contract has been 'artificially inflated' or whether the agreement genuinely reflects a prudent and efficient outcome.

JEN has applied its modified framework to examine its own outsourcing arrangements. In short, the results of this assessment indicate that:

- the contract price payable under the AMA (inclusive of margin and overheads) is lower than the costs that would be incurred if JEN was to provide the services in-house
- the non-price terms and conditions are consistent with (or in fact superior to) those that would be negotiated by parties operating on an arm's length basis

- the contract provides the contractor with strong and ongoing incentives to pursue efficiencies and to pass these back to JEN and in turn to users.

The AER should therefore accept the total contract price payable under the AMA as being consistent with clauses 6.5.6(c) and 6.5.7(c) and allow the price to be used as the basis for JEN's opex and capex, and when applying the EBSS.

In the following sections JEN:

- outlines JEN's key concerns with the AER's proposed framework and sets out the modifications it believes would be required to ensure a better alignment with the NEO and revenue and pricing principles (section 6.3.1)

- sets out JEN's response to the AER's assessment of both the AMA and the ESF arrangements (section 6.3.6)

- addresses a number of other issues that have been canvassed by the AER in its consideration of outsourcing arrangements (section 6.3.8)

- explains how costs incurred through JEN's outsourcing arrangements comply with the relevant opex and capex criteria (section 6.4).

JEN's response to the AER's draft determination on corporate overhead allocations is set out in section 7.3.3.

6.3.1 JEN's response to AER's proposed framework

JEN has a number of concerns with the AER's proposed framework and in particular, its proposed treatment of outsourcing arrangements that are deemed to fail the presumption threshold (Stage 2B of the AER's assessment framework). In short, these concerns stem from:

- the failure of this aspect of the proposed framework to recognise that while the relationship between contracting parties, or the conditions under which the contract was negotiated, may mean that the parties had an *incentive* to agree to an 'artificially inflated' price, a more detailed consideration of the price and terms specified in the contract is required to determine whether the parties *acted* upon the incentive

- the counterfactual adopted by the AER for the purposes of assessing forecast operating and capital expenditure and its decision to disregard the potential for a contractor to be able to access economies of scale, scope and other efficiencies that would otherwise be unattainable by the DNSP

- the reliance placed by the AER on the EBSS to be used to reward a contractor for efficiencies achieved during the regulatory control period

- the inconsistency of the current position taken by the AER on the margins payable under related party contracts with the position it has taken in other recent regulatory decisions.

The remainder of this section sets out JEN's specific concerns with these elements of the AER's proposed framework.

Was the incentive to agree to non-arm's length terms acted upon?

JEN appreciates the concerns that the AER has expressed about the *potential* for related party transactions to result in transfer pricing with the DNSP agreeing to pay an 'artificially inflated' price or other non-arm's length terms. However, as NERA pointed out in a report prepared for Multinet in 2007 entitled *Treatment of Outsourcing Arrangements*, a finding that a service provider entered into an outsourcing arrangement with a related entity is not, in itself, sufficient to conclude that transfer pricing had *actually* occurred between the service provider and the related entity.[108] NERA went on to note that to reach a view on this issue a more detailed consideration of arrangement and the prices contained therein would need to be undertaken to determine whether:

- the *incentive* the service provider may have had to engage in such behaviour was actually acted upon and resulted in it agreeing to pay an 'artificially inflated' price for the provision of services by the related party,[109] or

- the agreement constituted a more efficient outcome, with the contract price (including incremental co-ordination costs) being lower than the expected cost of the regulated service provider providing the services in-house.[110]

An agreement between related parties is likely to constitute a more efficient outcome than providing the services in-house, where the contractor is able to access economies of scale, scope and other efficiencies that would not otherwise be available to the DNSP. This point was explicitly acknowledged by the ESCV[111] when developing the framework to apply in the 2008-2012 GAAR and it was for this reason that it required contracts failing its presumption threshold to be subject to the in-house cost versus the contract price test (see Figure 6.2). The inclusion of this test in the ESCV's framework meant that a contract failing the presumption threshold, could still be viewed as a 'prudent and efficient outcome'[112] if the total

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108 Houston, G., *Treatment of Outsourcing Arrangements*, October 2007, p. 35.

109 Houston, G., *Treatment of Outsourcing Arrangements*, October 2007, p. 35.

110 Houston, G., *Treatment of Outsourcing Arrangements*, October 2007, p. 50.

111 ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 55.

112 ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 55.

price payable under the contract (including any margin) was found to be *less than or equal to* the costs that would be incurred if the services were provided in-house.

In JEN's opinion the approach employed by the ESCV in the 2008-2012 provides an appropriate basis upon which to determine whether an incentive to agree to the payment of an artificially inflated price was in fact acted upon or whether the contract genuinely reflects a more efficient outcome. JEN is therefore of the view that Stage 2B of the AER's proposed framework should be modified to incorporate the ESCV's in-house cost versus contract price test.

Counterfactual to apply when assessing forecasts

The second aspect of the AER's proposed framework that JEN has some concerns with relates to the counterfactual that it has decided to adopt when assessing forecast operating and capital expenditure. At its most elementary, the AER's counterfactual assumes that any economies of scale, scope and other efficiencies available to the contractor (including those derived from the provision of unregulated services and services to third parties) will also be available to the DNSP. The AER's counterfactual may therefore be viewed as sitting at the opposite end of the spectrum to the stand alone counterfactual.

As noted previously, the decision by the AER to adopt this counterfactual, rather than the stand alone counterfactual, is based on both an interpretation of the prudent operator criterion in clauses 6.5.6(c) and 6.5.7(c) and a workably competitive market hypothesis. JEN's view on these two matters is set out below.

AER's interpretation of the prudent operator criterion

The AER's decision to reject the use of the stand alone counterfactual has largely been based upon its interpretation of the prudent operator criterion contained in clauses 6.5.6(c)(2) and 6.5.7(c)(2) and, in particular, the phrase '*in the circumstances of the DNSP*'. The AER has contended that this phrase requires it to have regard to the DNSP's ownership structure and the efficiencies that would be available to the group to which the DNSP belongs, rather than those that would be available to the DNSP operating on a stand alone basis.

JEN disagrees with the AER's interpretation of this criterion and notes that it is inconsistent with:

- *the original intent of these provisions* — The phrase 'prudent operator in the relevant circumstances of the DNSP' was originally adopted by the AEMC in the context of drafting the Transmission Rules (Chapter 6A). [113] JEN has reviewed the material that was published by the AEMC as part of this

[113] AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006.

process, including the legal advice the AEMC received on the drafting of the expenditure criteria, and it is apparent from this material that the AEMC's intent was *not* to:

– infer inefficiency or imprudence from a DNSP's circumstances, and particularly its corporate structure. Rather, the intent was to require the AER to consider whether a DNSP's forecast expenditure reflects the costs that would be incurred by a prudent operator in those same circumstances. This would require, amongst other things, consideration be given to whether the DNSP has prudently sought to protect its own commercial interest in negotiations with the related party contractor, rather than favouring the interests of the contractor or the wider corporate group, which could be assessed by:

  ○ examining whether the price paid under the contract is less than, or equal to, the costs that would be incurred by the DNSP operating on a stand alone basis, since a prudent operator that is part of a broader corporate group would be expected to pay no more than the cost of in-house provision for services provided under the contract; and/or

  ○ comparing the terms and conditions specified in the agreement with those contained in contracts entered into by parties operating on an arm's length basis, to determine whether the terms agreed to by the DNSP and its related contractor are consistent with what one would expect to observe in an arm's length arrangement.

– focus on a DNSP's corporate structure. Rather the intent was to focus on the operational circumstances of the DNSP (ie, network size and the location of the network) rather than reflecting the ownership interests of the DNSP. Support for this view can be found in the following extract taken from the AEMC's Rule determination:[114]

> The introduction of more objective, **operationally focussed** decision criteria for the AER's assessment of whether or not it is satisfied with the basis of the forecasts, removes to a considerable degree the subjectivity associated with criteria such as reasonable or best estimates of expenditure requirements. [emphasis added]

114 AEMC, *Rule Determination – National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 53.

- *clauses 6.5.6(b)(2) and 6.5.7(b)(2) of the Rules* — Both clauses state that the forecast operating and capital expenditure must be for expenditure that is 'properly allocated to standard control services'. This limitation has been included to prevent any costs incurred by the DNSP in the provision of alternative control services, negotiated services or other unregulated services being passed through to end-users. In JEN's view, it could be reasonably inferred from this provision that if the costs associated with the provision of services *other* than the standard control service are to be disregarded when developing forecast expenditure, then so too should any efficiencies derived by the contractor from the provision of unregulated services. It follows that even if the AER is to have regard to the DNSP's ownership structure when assessing forecast operating and capital expenditure, it should *not* have regard to the efficiencies derived by the contractor from:

  - the provision of services to third parties

  - the provision of services to other entities in which the contractor's parent company has an interest, including other regulated entities

  - the provision of alternative control and negotiated services to the DNSP.

- *AER's approach to equity and debt raising costs* — When assessing the compliance of the Victorian DNSP's proposed equity and debt raising costs with the opex and capex criteria, the AER has based its assessment on a 'benchmark firm', which it describes as 'a pure play regulated electricity network operating in Australia *without* parent ownership'.[115] The position taken by the AER on ownership in this context is in direct contrast to the position it has taken with respect to outsourcing arrangements, notwithstanding the application of the same opex and capex criteria

- *AER's prior decisions* — In its prior regulatory decisions, the AER applied the stand alone counterfactual when assessing forecast operating and/or capital expenditure. A recent example of this inconsistency can be found in the AER's *Draft Decision – South Australia distribution determination 2010-11 to 2014-15*.[116] In this draft decision, the AER endorsed the use of the stand alone test employed by its consultant PB Associates, when considering the outsourcing arrangements entered into by ETSA Utilities and its related party, CHED Services

115 Draft decision, Appendix N, p. 265 and Appendix P, p. 329.

116 AER, *Draft Decision, South Australia distribution determination 2010-11 to 2014-15*, 25 November 2009, p. 206.

- *Tribunal decision* — The AER's decision to reject the use of the stand alone counterfactual is also at odds with the position taken by the Australian Competition Tribunal (**Tribunal**) in *Application by Optus Mobile Pty Limited & Optus Networks Pty Limited* (2007) ATPR 42-137 (Optus DGTAS). While this decision was made in the context of telecommunications, the principles discussed by the Tribunal in relation to the economies of scale and scope available to the service provider are equally relevant under the Rules and the NEL. In the case before the Tribunal, the ACCC submitted that it was not reasonable for Optus to apply the stand-alone counterfactual when determining costs.

The Tribunal disagreed with the ACCC and concluded that Optus' use of the stand alone counterfactual was 'reasonable':[117]

> We consider that determining the costs of a stand-alone mobile operator, for the purpose of determining whether the price terms of the undertaking in relation to Optus' DGTAS are reasonable, is more consistent with the matters set out in s 152AH and the objectives in s 152AB than requiring Optus to take into account the cost consequences of it being an operator of a fixed-line network and a mobile network. If the objective of regulating a particular industry is to replicate, as far as possible, the environment of a competitive market, then it is desirable to use as a benchmark criteria or principles which would exist in a competitive market, such as determining the costs of an operator operating in that market.
>
> Determining Optus' DGTAS costs as a stand-alone mobile operator would, all things being equal, be likely to result in the achievement of the objective of promoting competition in markets for listed services: s 152AB(2)(c). That is, in competing with mobile operators who do not operate a fixed line network, Optus may gain a competitive advantage by having access to economies of scale and scope. And Optus will not be at a disadvantage when competing against an integrated operator such as Telstra.
>
> Further, s 152AB(2)(e) requires us to have regard to the extent to which Optus' price is likely to result in the achievement of the objective of encouraging the economically efficient use of, and the economically efficient investment in, the infrastructure by which listed services are supplied. In turn, in determining the achievement of this objective, s 152AB(6)(b) requires us to have regard to the legitimate commercial interests of Optus, including its ability to exploit economies of scale and scope. Determining Opus' DGTAS costs on a stand-alone mobile operator basis promotes these objectives.

[117] *Application by Optus Mobile Pty Limited & Optus Networks Pty Limited* (2007) ATPR 42-137, 122 - 124.

Based on the foregoing it is clear that the AER's interpretation of the phrase 'in the relevant circumstances of the DNSP' in clauses 6.5.6(c)(2) and 6.5.7(c)(2) of the Rules is directly at odds with:

- the original intent of these provisions of the Rules
- other aspects of the forecast operating and capital expenditure related provisions in clauses 6.5.6 and 6.5.7
- the application of this provision by the AER in other areas of the Draft Detrmination and in prior regulatory decisions
- the Tribunal's Optus DGTAS decision.

The weight of these inconsistencies is, in JEN's view, sufficient to conclude that the AER has incorrectly assumed that clauses 6.5.6(c)(2) and 6.5.7(c)(2) would allow it to have regard to the costs that the corporate group to which the DNSP belongs would incur rather than the costs that a prudent operator in the same operational circumstances as the DNSP would incur. Consistent with the Tribunal's decision in the Optus DGTAS decision, JEN is of the view that any assessment of operating and capital expenditure forecasts under the Rules should be made by reference to the stand alone counterfactual and not the more stringent counterfactual that the AER has sought to employ in this occasion.

AER's workably competitive market hypothesis

The AER has also sought to dismiss the need to consider whether a contractor could access efficiencies not otherwise available to a DNSP, by hypothesising that in a workably competitive market, contractors would be unable, in the long run, to charge a margin above its 'full economic costs and earn abnormal profits due to the efficiencies available to the contractor that are not currently available to the service provider or other contractors'.[118]

There are, in JEN's view, two key problems with the hypothesis, as described by the AER, and its proposed application of the hypothesis:

- First, while in theory any 'abnormal profits'[119] earned by a contractor operating in a workably competitive market can be expected to be competed away over the *longer* term, it is possible in the short to medium term that contractor's may be able to generate 'abnormal profits'. The AER appears to

[118] Draft decision, p. 182.

[119] JEN notes that the AER's definition of the term 'margin' changes in this context from being an amount in excess of the contractor's actual costs (both direct and indirect costs) to being an amount above the 'full economic cost' of delivering the service. If the direct and indirect costs are lower than the in-house cost of provision then any difference between the two measures could result in a margin being maintained in a workably competitive market over the longer run.

have given no consideration to the potential for this to warrant the payment of a margin in the short to medium term.

- Second, and perhaps most importantly, the results of benchmark studies of margins earned by contractors supplying comparable services to those procured by the Victorian DNSPs, provide clear evidence that the majority of contractors consistently earn margins in *excess* of the amounts viewed by the AER as constituting an acceptable basis for a margin.[120]

Viewed in this way it is apparent that the AER's decision to exclude a margin to reflect the difference in the relative ability of the contractor and DNSP to access economies of scale, scope and other efficiencies is ill-conceived and inconsistent with observed outcomes.

Relevance of services provided by a contractor to third parties

The discussion of the cost allocation prices referred to above touched on the issue of the extent to which efficiencies derived from the contractor from the provision of services to third parties should be taken into account. As noted in this discussion, JEN is of the opinion that any efficiencies derived from the provision of these services should not be assumed to be attainable by the DNSP.

The issue of third party service provision by the contractor raises two other important points that the AER has not considered:

- First, where the contractor provides services to third parties, the price charged to the related party should be *no* more or less favourable than the price the contractor would be able to achieve if it were to supply the services in a competitive market.

- Second, where the contractor provides services in a competitive market to third parties, the prices paid under those contracts can provide some insight into the price that the DNSP would have paid if the contract had been the subject of a competitive tender. Specifically, if the price paid by the DNSP to its contractor is less than, or equal to, the price paid by other third parties that have retained the contract, then this could provide further evidence that

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[120] See for example:

- NERA, *Allen Consulting Group's Review of NERA's Benchmarking of Contractors' Margins Critique*, October 2007, p. v.
- Impaq Consulting, *Review of rates in proposed ACS Charges*, 25 May 2010, p. 36.

The metric used to measure margins in each of these studies was the earnings before interest and tax (EBIT) margin. EBIT is the amount received by a contractor in excess of the amount it requires to recover its overheads and a return of assets (depreciation). The sample of entities used in each of these studies was limited to those entities exhibiting a relatively low level of capital intensity. One would expect therefore that any portion of the margin attributable to a return on capital to be relatively small.

the price is efficient and reflects the price that what would have been struck in a competitive market.

Consequences of the AER's proposed counterfactual

Setting aside for one moment the question of whether the AER's counterfactual is the correct one to adopt, if the AER were to employ its proposed counterfactual and prevent any margin in excess of the contractor's actual costs (including directly incurred costs, overheads and a return on and of capital) being recovered from users, then the arrangement would be commercially unviable. To the extent that the arrangement is a genuinely more efficient outcome than providing the services in-house—because the contractor can access efficiencies not otherwise available to the DNSP—then the approach would result in the DNSP receiving less than the efficient cost of providing the service. This would in turn adversely affect:

- the DNSP's investment decisions
- utilisation decisions by end-users of the DNSP's assets
- the incentives a DNSP has to pursue productive and dynamic efficiencies.[121]

These adverse effects would continue until such time as the outsourcing arrangement could be terminated by the DNSP and the services could be brought back in-house. Importantly, the decision by the DNSP to bring the services back in-house will not be made on the basis of whether it is efficient to do so. Rather, the AER's proposed treatment can be expected to result in the services being brought back in-house even in those circumstances where the price that would be paid to the contractor is lower than the cost that would be incurred if the services were provided in-house. Such an outcome would, as NERA observed in its report for Multinet, be 'perverse'[122] and would result in users paying higher charges over the longer run.

Another outcome that has not been considered by the AER is that if a DNSP were to bring the services back in-house, then it may no longer be commercially viable for the contractor to continue to operate. If this were to occur, then any efficiencies derived by the contractor from the provision of services to other parties would be lost. Such an outcome would again adversely affect users, with the costs incurred by the DNSP being higher than they would otherwise have been.

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121 Farrier Swier Consulting, *JGN Gas Networks (JGN) Access Arrangements 2010: Approach to Opex Forecasts, Expert Opinion – Geoff Swier*, March 2010, paragraph. 111 (JGN submitted this report to the AER on 19 March 2010 as Appendix 9.1 of its revised access arrangement proposal).

122 NERA, *Treatment of Outsourcing Arrangements*, October 2007, p. 43.

Viewed in this way it is apparent that if the AER's counterfactual were to be employed, it could adversely affect the overall efficiency of the sector and in the longer run result in users paying higher charges.

Conclusion

For the reasons set out above, JEN is of the opinion that any assessment of a DNSP's operating and capital expenditure forecasts should be made having regard to the stand alone counterfactual.

6.3.2 Efficiency benefit sharing scheme

Another aspect of the AER's proposed framework that JEN has concerns with is the reliance placed by the AER on the EBSS (and its predecessor, the ECM) to reward contractors for efficiencies achieved during the regulatory control period.[123]

One factor that the AER appears to have overlooked in this context is that these incentive schemes only apply to operating expenditure. The operation of these schemes will not therefore provide adequate compensation for efficiencies achieved by the contractor with respect to capital expenditure. This point was implicitly acknowledged by the AER in its consideration of the margin that it would allow DNSPs to recover in the provision of alternative control services, as reflected in the following statement:[124]

> In conclusion, in applying the AER's general approach to outsourced transactions and profit margins outlined in chapter 6, the AER finds that it may be efficient for alternative control services charges (being provided either in-house or via an outsourced contract) to incorporate profit margins. **This is because in the absence of an EBSS for alternative control services, there isn't a mechanism to reward efficiencies generated during the current regulatory control period beyond 2010.** [emphasis added]

The reliance that a DNSP could place on recovering sufficient compensation through the EBSS to reward its contractor for achieving efficiencies during the regulatory control is also somewhat questionable, given the level of uncertainty surrounding how the scheme may operate in the future. Since the introduction of the original efficiency carryover scheme by the ESC, the scheme has been subject to a number of significant changes. The uncertainty created by these changes, coupled with the potential for future exercises of regulatory discretion to affect the allowance provided to the DNSP, means that DNSPs can place little reliance on the scheme providing adequate compensation.

[123] Draft decision, p. 182.

[124] Draft decision, p. 860.

Finally, it is not clear to JEN why the AER has not applied the same line of logic to contracts that pass the presumption threshold given the argument that the scheme provides adequate compensation for the efficiencies achieved by contractors is of equal relevance to these types of contracts. The same question could be posed in relation to the AER's workably competitive market hypothesis, which would also appear to be of equal relevance to contracts that both pass and fail the presumption threshold.

6.3.3 Inconsistency with other recent decisions on margins

The final concern that JEN has with the AER's proposed approach, is that the position it has taken on the margins payable under contracts that fail the presumption threshold is inconsistent with the approach that it has recently taken in the JGN and the ActewAGL final decisions.

In the JGN draft decision, the AER's concerns with the related party nature of the AMA and the information provided by JGN to substantiate the price payable under the agreement led it to conclude that the margin payable by JGN to JAM should be excluded from both forecast operating and capital expenditure.[125] While voicing similar concerns in the JGN Final Decision, the AER decided to allow a margin in the Final Decision subject to the caveat that it was not applied to services sub-contracted by JAM. [126] In doing so, the AER acknowledged that the payment of a margin to a contractor was:

- 'not inconsistent with' the relevant provisions of the National Gas Rules (NGR)[127], which have a very similar objective to the National Electricity Rules
- appropriate at a level consistent with the implicit margin arising from JAM's revealed costs in the 2008–09 base year[128]
- 'consistent with the benchmarking evidence' at the level it determined.[129]

The AER's ActewAGL Final Decision was released three months prior to the draft decision and in this decision the AER identified similar concerns to those outlined

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125 AER, *Draft decision – Jemena Gas Networks, Access arrangement proposal for the NSW gas networks*, 10 February 2010, pp. 184-5.

126 AER, *Final decision – Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015,* 11 June 2010, p. 273.

127 AER, *Final decision – Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015,* 11 June 2010, p. 268.

128 AER, *Final decision – Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015,* 11 June 2010, pp. 56 & 269.

129 AER, *Final decision – Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015*, 11 June 2010, p. 270.

above but ultimately allowed the entire margin payable by ActewAGL to JAM to be included in the derivation of forecast operating expenditure.[130]

While each of these decisions was made under the NGR and the National Gas Law, the operating and capital expenditure criteria are broadly similar to those specified in the Rules. One would therefore expect some consistency in the approaches employed in the regulation of both gas pipelines and electricity networks. The AER's rationale for applying a different approach to the Victorian DNSPs to that employed in these two decisions has not been made clear in the draft decision. Nor has the AER explained why, when developing its proposed assessment framework,[131] it considered the approach taken in the JGN draft decision but not the approach that was ultimately taken in the final decision, which was released just one week after the AER's draft determination for JEN.[132] The lack of consistency between these decisions and the absence of any reason for the difference in approach is, in JEN's view, peculiar and contrary to one of the Ministerial Council on Energy's principal objectives in implementing further reforms in the gas and electricity sectors, which was to develop a 'common approach to revenue and network pricing across the energy market'.[133]

6.3.4 Conclusion on the AER's proposed framework

To summarise, the AER's proposed treatment of outsourcing contracts that fail its presumption threshold has a number of fundamental shortcomings which can broadly be characterised as relating to:

- the AER's failure to recognise that while the parties to an agreement may have had an *incentive* to agree to an 'artificially inflated' price at the time the contract was negotiated, a more detailed consideration of the price and terms specified in the contract is required to determine whether the parties *acted* upon the incentive

- the AER's view on the counterfactual that should be employed when assessing forecast operating and capital expenditure and its rationale for dismissing the potential for a contractor to be able to access economies of scale, scope and other efficiencies that would otherwise be unattainable by the DNSP (that is, its interpretation of the prudent operator and the workably competitive market hypothesis), which is inconsistent with:

[130] AER, *Final decision, Access arrangement proposal – ACT, Queanbeyan and Palerang gas distribution network*, 26 March 2010, pp. 91-2.

[131] Draft decision, p. 168.

[132] Ibid.

[133] MCE, *Communiqué*, 4 November 2005, p. 1.

- the original intent of the provision 'prudent operator in the relevant circumstances of the DNSP'
- clauses 6.5.6(b)(2) and 6.5.7(b)(2) of the Rules
- prior regulatory decisions by the AER, the ESCV and the Tribunal
- other aspects of the AER's draft decision
- commercial evidence of the margins earned by contractors

- the reliance placed by the AER on the EBSS to be used to reward a contractor for efficiencies achieved during the regulatory control period
- the inconsistency of the current position taken by the AER on the margins payable under related party contracts with the position it has taken in both the ActewAGL and the JGN Final Decisions.

One of the more fundamental shortcomings with this aspect of the AER's framework is that it fails to recognise the potential for an outsourcing contract that cannot be presumed to be efficient to genuinely constitute a more efficient outcome because it assumes unreasonably that the DNSP will be able to access the same economies of scale, scope and other efficiencies that would be available to a contractor that provides services to any number of related and unrelated parties.

The practical effect of this assumption is that an outsourcing contract that is deemed to fail the presumption threshold will never be viewed as a more efficient means of delivering a service than the DNSP providing the services in-house. As a consequence, DNSPs will have a perverse incentive to provide services in-house even in those cases where outsourcing constitutes a genuinely more efficient outcome than providing the services in-house because the contractor can access efficiencies not otherwise available to the DNSP. In the longer term users will ultimately be the ones that bear the costs associated with any inefficiencies arising from bringing the services in-house and any loss of efficiencies available to the contractor from the provision of services to third parties. In the short to medium term, the application of the AER's framework in its current form could result in those DNSPs that have entered into contracts that fail the presumption threshold:

- failing to recover at least the efficient costs they incur in providing direct control network services, which could result in an inefficient level of utilisation of the DNSPs assets
- being accorded insufficient incentives to promote economic efficiency
- under-investing in the distribution networks.

Such an outcome would be contrary to a number of the revenue and pricing principles—subsections 7A(2), (3), (6) and (7) of the NEL—and inconsistent with the NEO.

6.3.5 JEN's proposed framework

In view of the deficiencies outlined above, JEN has considered what modifications would be required to address each of the issues outlined in the preceding section and ensure that the approach is more consistent with the NEO and revenue and pricing principles. In doing so, JEN has carefully considered the approach adopted by the ESCV in the context of the 2008-2012 GAAR, which was subject to a robust consultation process that was informed by submissions from a range of interested parties and expert reports prepared by a number of economic consultants.

Given the backdrop against which this framework was developed, JEN is of the view that the second stage of the AER's framework applying to contracts failing the presumption threshold (Stage 2B) should be modified to bring it into the line with the approach adopted by the ESCV in the 2008-2012 GAAR. Specifically, the framework should be modified to recognise the potential for the contract price to still be consistent with the operating and capital expenditure criteria in the Rules, where a DSNP is able to demonstrate that the contract price is *equal to* or *lower* than the costs that would be incurred if the services were provided in-house, where the in-house cost of provision is calculated by reference to the stand-alone counterfactual. If a DNSP is able (unable) to demonstrate that this is the case, then, in the absence of further evidence or material, the contract price (in-house cost) should form the basis for the DNSP's forecast operating and/or capital expenditure and the measurement of operating expenditure used in the EBSS. In adopting this approach, JEN notes that this may not necessarily be the only circumstance in which an outsourced contract price associated with a contract between related parties may be considered to be consistent with the operating and capital expenditure criteria. However, JEN considers that if this test can be met, the contract price will be consistent with the operating and capital expenditure criteria.

In keeping with the ESCV's approach, if the cost of in-house provision is to be measured using the contractor's direct costs as the starting point, then consideration will also need to be given to the additional allowance required to reflect:

- the return on and of assets required by the contractor for those assets that it owns and are used in the provision of services to the DNSP
- an appropriate portion of the contractor's common costs

- the economies of scale, scope and other efficiencies *not* otherwise available to the DNSP operating on a stand alone basis.

While ascribing a value to the first two of these items will be relatively straightforward, in practice it may not be possible to quantify, with any degree of precision, the value of efficiencies that are available to the contractor but not otherwise available to the DNSP. JEN has therefore given further consideration to the other factors the AER could use to satisfy itself when assessing whether the contract price is likely to be less than the in-house cost of provision and therefore consistent with the operating and capital expenditure criteria specified in clauses 6.5.6(c) and 6.5.7(c) of the Rules.

One alternative that could be employed, where the contract price is based on a cost pass through pricing structure, would involve undertaking an inquiry to determine whether:

- the contractor's costs (both directly and indirectly incurred costs and an appropriate share of common costs) are *lower* than those that could be achieved by the in-house service provider operating on a stand alone basis

- the margin (defined in this context as an amount in excess of the contractor's directly and indirectly incurred costs and an appropriate share of common costs) is *comparable* to that charged by other contractors for similar levels of risk and does not exceed the expected benefits of the economies of scale, scope and other efficiencies offered by the contractor.

Provided these two factors are satisfied, it would be reasonable for the AER to infer that the contract price (that is, the contractor's costs plus the margin) is lower than the in-house cost of provision and therefore *consistent* with the operating and capital expenditure criteria specified in clauses 6.5.6(c) and 6.5.7(c) of the Rules.

The results of benchmark studies may provide further support for this inference where an outsourcing arrangement accounts for a substantial proportion of a DNSP's total expenditure. In such circumstances, the results of benchmark studies can be expected to provide some indication of whether the total price payable under the contract is efficient and consistent with the costs that a prudent operator in the circumstances of the relevant DNSP could be expected to incur. JEN understands that the AER has some concerns with the reliance that can be placed on benchmark studies and while it agrees that benchmarking can not, in and of itself, be relied upon to demonstrate consistency with the operating and capital expenditure criteria, it is a further piece of information that can provide greater insight into whether the total price payable under the contract is efficient and/or consistent with what would be incurred by a prudent operator DNSP.

Another factor that will be relevant to consider in this context is the extent to which the non-price terms and conditions specified in the outsourcing arrangement are consistent with those that one would expect to observe in an arm's length arrangement. Consistent with the approach adopted by the ESCV in the 2008-2012 GAAR, an assessment of these provisions should focus on:[134]

- the scope of the services to be provided under the contract
- the governance arrangements contained in the contract and the extent to which these arrangements give rise to an appropriate allocation of responsibilities and accord the DNSP with sufficient control over its assets and expenditure.

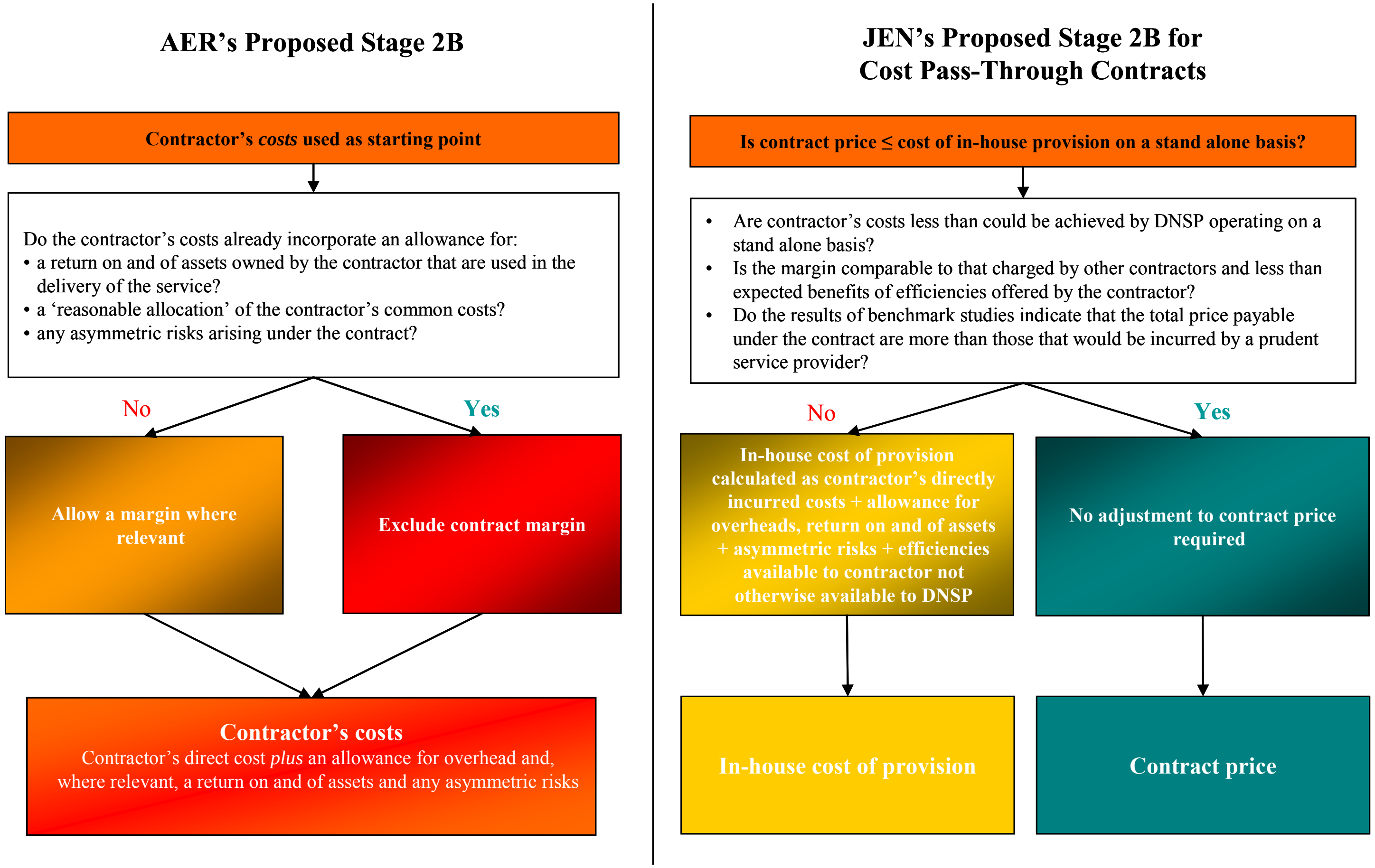
Another factor that the ESCV noted would be relevant to consider in this context is the incentive arrangements specified in the contract and the extent to which these arrangements provide the contractor with an incentive to pursue productive and dynamic efficiencies over the contract term, and to pass those efficiencies back through to the service provider.[135] JEN agrees that this is an important factor to consider and where provision is made for this to occur, the AER should be able to draw some comfort that the contractor's incentives are aligned with the relevant provisions of the Rules, the national electricity objective and a number of the revenue and pricing principles.

Figure 6-3 illustrates the modifications that would be required to be made to the AER's proposed framework to reflect these changes.

[134] ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 54.

[135] ESC, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 54.

Figure 6-3: JEN's Proposed Modifications to the AER's Framework



6.3.6 JEN's response to the AER's assessment of JEN's outsourcing

At the time the AMA was entered into both JEN and JAM were owned by SPI (Australia) Assets. JEN therefore accepts that, by reference to the AER's assessment framework, the AMA may not be *presumed* to be consistent with the opex and capex criteria. However, for the reasons set out in the preceding section JEN does *not* agree with the approach employed by the AER when considering the relevance of the price payable under these agreements. JEN has therefore applied its own proposed framework, as described in section 6.3.5, to the AMA to assess whether:

- the price payable under the contract is greater than the costs that would have been incurred if the services were provided in-house on a stand alone basis. Since the AMA is essentially a cost pass-through contract, this aspect of the assessment has been made by considering whether:
  - JAM's costs (including its directly and indirectly incurred costs and recovery of overheads) are lower than those that would be incurred if JEN were to provide the services in-house on a stand alone basis
  - the margin payable under the AMA is comparable to that charged by other contractors for similar levels of risk and does not exceed the expected benefits of the economies of scale, scope and other efficiencies offered by JAM
  - the total price payable by JEN under the AMA is efficient and/or consistent with the costs that would be incurred by a prudent DNSP having regard to capex and opex benchmarking
- the non-price terms and conditions specified in the contract are consistent with what one would expect to observe in an arm's length contract
- the contract provides JAM with sufficient incentive to pursue productive and dynamic efficiencies and to pass these back to JEN and, in turn, to end-users.

The results of this assessment are set out in Appendix 6.12. In short, the results indicate that:

- JAM's costs (including its directly and indirectly incurred costs and its recovery of overheads) are lower than those that could be achieved by JEN operating on a stand alone basis

- the margin payable under the AMA is comparable to that charged by other contractors and does not exceed the expected benefits of the economies of scale, scope and other efficiencies offered by JAM.

The results of the opex and capex benchmarking studies provide further support to the conclusion that the total price payable under the AMA including the margin is consistent with the operating and capital expenditure criteria specified in the Rules. Specifically, the results of opex benchmarking undertaken by the UMS Group[136] and capex benchmarking undertaken by the AER in conjunction with Nuttal Consulting,[137] demonstrate that when compared against the industry average, the total price payable under the AMA including the margin (and its predecessor, the Letter Agreement) for both operating and capital expenditure is efficient.

Additional support for the view that the price payable under the AMA (including the margin) is consistent with with the operating and capital expenditure criteria specified in the Rules can be found in both:

- the non-price terms and conditions specified in the AMA, which are consistent with what one would expect to observe in an arm's length contract
- the incentive mechanisms contained in the AMA, which will ensure that over the contract term JAM's incentive to pursue both productive and dynamic efficiencies will be aligned with the relevant incentive provisions in the Rules, the NEO and several of the revenue and pricing principles.

The AER should therefore accept that the price payable under the AMA—including both the base and performance margin—is consistent with the operating and capital expenditure criteria contained in clauses 6.5.6(c) and 6.5.7(c) and may be used as the basis for JEN's forecast operating and capital expenditure for the 2011-2015 regulatory control period and the operation of the EBSS.

6.3.7 Response to contract specific issues raised by the AER

Within its assessment of the AMA and/or the ESF, the AER raised a number of issues about the overheads payable by JEN to Jemena Limited and various aspects of the margin studies referred to by JEN in it is initial regulatory proposal. JEN's response to each of these issues is set out below.

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136 UMS Group, *Jemena Electricity Networks (JEN) – Victoria AUS, Operating expenditure efficiency review*, 15 July 2010, slides 8, 20, 31 and 36 (Appendix 6.11).

137 Draft decision, Appendix I, pp. 60-1.

Overheads

In Appendix H.3.2 and Appendix H.3.3 of its draft decision, the AER has expressed a number of concerns about the quantum of overheads allocated to JEN under the ESF and the AMA and has sought to exclude the management fees and other finance/investment analysis/energy investment costs payable to Jemena Limited because it contended that they do not relate to the provision of the distribution services and should therefore be excluded from the operating and capital expenditure forecasts.[138]

For the reasons set out in section 7.3.3, JEN disagrees with the conclusion reached by the AER about the relevance of the energy investments, investment analysis and financial strategy components of the overhead to the provision of distribution services and its decision to exclude these components from JEN's operating and capital expenditure forecasts.

Margin studies

In its assessment of the AMA the AER raised a number of issues about the margin studies referred to by JEN in its initial regulatory proposal. The issues can broadly be categorised as relating to:

- the consistency of the base margin with the range estimated by NERA
- the influence that asset ownership could be expected to have on the comparability of the AMA with other studies
- the risks arising under the AMA relative to those arising under other agreements.

Given the confidential nature of the margin payable under the AMA, JEN's detailed response to each of these issues is set out in Appendix 6.12. In short, JEN is of the opinion that:

- the issues raised by the AER are misguided
- the margin studies that it relied upon when negotiating the AMA clearly demonstrate that the overall margin payable under the AMA is comparable to the margins charged by other contractors for similar levels of risk.

Range estimated by NERA

In its discussion of the benchmark study prepared by NERA, the AER observed that the base margin is above the average industry EBIT margin measured by

[138] Draft decision, pp. 199-208.

NERA and ‘towards the higher end of the 95 per cent confidence interval’. On the basis of these observations the AER concluded that ‘there is not a clear verification of the {c-i-c} margin against industry benchmarks’.[139]

While the AER has correctly observed that the base margin is above the average measured by NERA, it appears to have misunderstood the purpose of the 95 per cent confidence interval. The 95 per cent confidence interval does *not* reflect the range for the entire sample, as the AER appears to have assumed. The range for the sample was {c-i-c}. Rather, the {c-i-c} confidence interval calculated by NERA is a measurement of the confidence interval surrounding the *true population mean*. Expressed another way, the specification of the confidence interval allows one to be 95 per cent confident that the true population mean lies within the range {c-i-c}. Thus, contrary to the view expressed by the AER, the results of this study do provide a ‘clear verification of the {c-i-c} margin against industry benchmarks’.

On a separate but related issue, JEN notes that the position taken by the AER on benchmark studies is at odds with the position it took in the JGN Final Decision. In this decision, the AER had regard to a number of benchmark margin studies (including the Impaq Consulting study that was commissioned by the AER in the context of this review) and concluded that the base margin of {c-i-c} was ‘consistent with the benchmarking evidence’.[140] It is not clear from the information contained in the draft decision why the AER has reached an alternative view with respect to the JEN AMA, when it is almost the same as the JGN AMA in all relevant respects and the AER was considering both AMAs at the same time.

Asset ownership

The issue of asset ownership and the influence it could be expected to have on the margins earned by contractors is touched upon by the AER in Appendix H.3.2. JEN agrees with the AER that in circumstances where a contractor owns and utilises its own assets in the provision of services, it would expect to earn a higher margin than contractors that do not own those assets. However, this issue has been addressed in a number of the studies JEN considered, with the authors of these studies limiting the entities included in the sample to those that utilise a small proportion of capital in the generation of revenue.

For example, in the NERA study the sample was limited to those entities exhibiting a capital intensity ratio (measured as the ratio of depreciation to revenue) of less

[139] Draft decision, Appendix H, p. 18.

[140] AER, *Final Decision, Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015*, 11 June 2010, p. 270.

than 3 per cent.[141] This point was also recognised by Impaq Consulting when selecting the sample of entities to be used when assessing the appropriate margin to be included in alternative control service charges.[142] By limiting their respective samples to contractors that use a relatively low proportion of assets in the derivation of revenue, the results of each of these studies can be viewed as providing some insight into the margin that a contractor using similarly low levels of physical capital to those used by JAM, would expect to earn from the provision of services. The results of these studies are therefore directly relevant to the consideration of whether the base margin payable to JAM is comparable with those charged by other contractors.

Alliance style agreements

In Appendix H.3.2 of its draft decision, the AER has sought to dismiss JEN's claim that the AMA gives rise to additional risks that would not be reflected in an industry based average and would therefore warrant the payment of the performance margin. In doing so, the AER has referred to a statement contained in the Evans & Peck report about the common use of alliance style contracts in the power sector.[143]

The mere fact that alliance style contracts are commonly used in an industry does not mean that the level of risks arising under each contract is the same. To the contrary, the allocation of risks in individual contracts can be expected to vary markedly across contracts and as a result the price agreed in individual contracts can be expected to differ. JEN understands that the level of risk to which JAM is exposed under the AMA is *greater* than that faced under other alliance style contracts. The inference that the AER has attempted to draw from the Evans & Peck report about the risks faced by JAM under the AMA is therefore, in JEN's view, ill conceived.

Further information on the unique risks faced by JAM under the AMA is contained in Appendix 6.12.

Conclusion on margin studies

In JEN's view the margin studies that it relied upon when negotiating the AMA clearly demonstrate that the overall margin payable under the AMA is comparable to the margins charged by other contractors for similar levels of risk. Further information on these studies is contained in Appendix 6.12.

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[141] NERA, *Benchmarking contractor's profit margins*, 28 March 2007, pp.8-9 and Ferrier Hodgson, *Expert's Report In Respect of United Energy Distribution Pty Ltd Advanced Interval Meter Price Review*, 12 June 2008, p. 16.

[142] Impaq Consulting, *Review of rates in proposed ACS Charges*, 25 May 2010, p. 36.

[143] Draft decision, Appendix H, p. 18.

6.3.8 Other issues raised by the AER

Within chapter 6 and Appendix H of the draft decision, the AER canvassed a range of other issues that are, in JEN's view, worth exploring further. The specific issues referred to in this context include:

- the relevance of benchmark margin studies
- the methods proposed by the AER to eliminate any double counting of systematic risks across an outsourcing agreement and other aspects of the DNSP's building block proposal
- the payment of a margin to a contractor on services that are sub-contracted
- the relevance of the ESCV's Electricity Industry Guideline No. 3.

Relevance of benchmark studies of margins

The relevance of benchmark margin studies is considered by the AER in section 6.5.5 of the draft decision and its view on this issue is summarised in the following excerpt:[144]

> Whether or not a margin should be allowed, and the magnitude of that margin if allowed, should not simply be a matter of comparing the margin earned by a related party against industry benchmarks.

JEN accepts that the results of a benchmark study of margins can not, in and of themselves, be relied upon to demonstrate that the price payable under an outsourcing agreement is consistent with the operating and capital expenditure criteria. However, none of the DNSPs in this case has sought to use the studies in this manner. Rather, the margin studies have been just one element of more extensive submissions that have sought to demonstrate that the overall price payable under the contract is consistent with clauses 6.5.6(c) and 6.5.7(c).

In JEN's view, these types of studies do have a role to play, particularly when the contract in question is a cost pass–through contract. In such circumstances, a benchmark study of the margins earned by contractors providing comparable services to those provided under the contract, can provide some insight into whether the margin payable under the contract is in line with industry averages. Of course before any reliance can be placed on such studies careful consideration must be given to whether the metric used in the studies, which may be measured on a pre- or post-overheads and/or return on and of capital basis, reflects the nature of the margin payable under the contract in question. If this is the case then the results of the study can have a role to play in an assessment of whether the

144 Draft decision, p. 186.

margin is in excess of the industry average and a broader consideration of whether the overall price payable under the outsourcing arrangement was 'artificially inflated'.

There is therefore, in JEN's view, no basis for the AER to dismiss the relevance of these studies where a DNSP is able to demonstrate that the margins are measured on a consistent basis. Further consideration is given to the comparability of the base margin payable with the metric used in the benchmark margin studies relied upon by JEN when agreeing to the payment of this margin in Appendix 6.12.

Another point that is worth noting in this context is that the AER's view on this issue is directly at odds with:

- *the AER's JGN Final Decision* — while raising a number of concerns with benchmark studies the AER's decision to allow the base margin appeared to be largely based on the observation that the margin was 'consistent with the benchmarking evidence'[145]

- *the AER's consultant* — Impaq Consulting used the results of a study of EBIT margins to identify the profit margin that should be used in the calculation of alternative control service charges.[146]

Double counting of systematic risks

The issue of double counting between the contract price and other aspects of a DNSP's building block proposal is considered by the AER in section 6.5.3 of the draft decision. In this section the AER discusses the potential for an outsourcing arrangement to result in a transfer of systematic risk from the DNSP to the contractor and the methods that could be employed to remove the effect of any double counting. The two methods considered by the AER in this context involved either adjusting the contract price or reducing the DNSP's WACC, although it conceded that either approach may be difficult to implement in practice.[147]

JEN agrees with the AER that any attempt to quantify the effect of an outsourcing arrangement on the systematic risk of a DNSP, and the adjustments that would be required to be made to either the contract price or the DNSP's WACC, is likely to pose a number of significant challenges. Some consideration was given to this issue by NERA in a report prepared for Envestra in 2007 entitled *Outsourcing by regulated business.* The clear conclusion emerging from this report was that any

[145] AER, *Final Decision, Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015*, 11 June 2010, p. 270.

[146] Impaq Consulting, *Review of rates in proposed ACS Charges*, 25 May 2010, p. 36.

[147] Draft decision, p. 176.

attempt to adjust the WACC to reflect changes in systematic risk would be a complex task and should not be embarked upon lightly by a regulator.[148]

JEN agrees with the conclusions reached by NERA on this issue and therefore cautions the AER against employing either method before a more fulsome consideration of this issue is undertaken.

It is also worth noting in this context that while the pricing structure adopted in JEN's AMA comprises a 'fixed cost component', the overall pricing structure is more akin to a cost pass-through contract than a fixed price contract (see Appendix 6.12). It should not therefore be viewed as giving rise to any significant transfer of systematic risk.

Margin on services that are sub-contracted

Another issue that the AER has raised in its draft decision is the appropriateness of allowing a contractor to levy a margin on work that is then sub-contracted. This issue was originally raised by the AER in the context of the JGN draft decision. Within the draft decision the AER reaffirmed the views expressed in the JGN draft decision and in doing so, stated:[149]

> The AER also continues to support the third principle that 'cascading margins' resulting from entities that do not themselves contribute to the provision of an intermediate service are not an efficient cost structure.

JEN disagrees with the AER's characterisation of this issue and notes that the approach ensures that the head contractor's incentive to provide the services at the lowest sustainable cost is *not distorted* by any difference in its ability to generate a margin. For example, if the AMA only allowed JAM to recover a margin for the work it undertook then it would have a clear incentive to carry out the work itself notwithstanding the potential to sub-contract the work to a specialist provider that could provide the services at a lower cost than JAM. From JEN's perspective this would be a more *inefficient* outcome than allowing JAM to recover a margin on the work that it sub-contracts.

The inefficiency that would arise if JAM's incentive to pursue the lowest sustainable cost was distorted can be seen in the following example, which assumes that a sub-contractor could provide the services for $90 while the cost of JAM providing the services (*excluding* any margin) was $100. In this example, allowing JAM to recover a margin of {c-i-c} on the sub-contracted services would result in an overall cost of {c-i-c} as opposed to the {c-i-c} that would otherwise be payable if JAM had provided the services itself. As this example

148 NERA, *Outsourcing by regulated businesses*, 28 March 2007, Appendix A.

149 Draft decision, p. 168.

demonstrates, allowing JAM to recover a margin on work that is sub-contracted will always be a more efficient outcome when the price that the sub-contractor is able to undertake the work for is lower than the cost that JAM could provide the services.

Viewed in this way it is apparent that allowing JAM to recover a margin on work that is sub-contracted will only be inefficient if the price payable to the sub-contractor is higher than the cost that JAM would incur if it provided the services. Given the incentive mechanisms contained in the AMA and the 'Efficient Cost' limitation embodied in the contract (see Appendix 6.12) there is no reason to expect that JAM would have any incentive to sub-contract in these circumstances.

For the reasons set out above JEN disagrees with the position taken by the AER on this issue.

ESCV's Electricity Industry Guideline No. 3

In section 6.5.7 of the draft decision the AER refers to the requirement in the ESCV's Electricity Industry Guideline No. 3 that expenditures be reported net of the margins payable to related parties because such margins were regarded by the ESCV as 'not reflecting the costs of providing regulated services'.[150]

While the AER does not appear to place any reliance on the guideline, JEN notes the Tribunal's finding in *Application by United Energy Distribution Pty Ltd [2009] ACompT 10,* that the guideline should not be construed as limiting the expenses that can be recovered by a DNSP through the application of another regulatory instrument.[151] Given the Tribunal's finding on this matter, JEN would expect the AER in the final determination not to rely on the guideline as a ground for rejecting the margins payable under outsourcing arrangements that fail the presumption threshold.

6.4 Compliance with the Rules

In JEN's view the modifications that it has made to the AER's proposed framework for assessing outsourcing arrangements is more consistent with the Rules, the NEO and the revenue and pricing principles than the AER's proposed approach. Specifically, by requiring a more detailed assessment to be undertaken to determine whether the price struck under the contract was actually 'artificially inflated' and/or the non-price terms and conditions were inconsistent with what one would expect to observe in a non-arm's length contract, JEN's proposed framework ensures that appropriate consideration is given to whether the arrangement is consistent with the efficient cost and prudent operator aspects of the opex and

150 Draft decision, p. 189.

151 *Application by United Energy Distribution Pty Ltd [2009] ACompT 10,* December 2009, para 61.

capex criteria (clauses 6.5.6(c)(1)-(2) and 6.5.7(c)(1)-(2) of the Rules). The application of the in-house cost versus contract price test under JEN's proposed framework will also ensure that DNSPs that have entered into contracts that genuinely constitute a more efficient outcome than providing the services in-house will not be unfairly penalised and will not have a perverse incentive to bring the services in-house.

In contrast to the AER's proposed framework, the application of JEN's framework will ensure that in cases where contracts are found to be efficient (ie, the contract price is less than or equal to the cost of in-house provision) the DNSP is able to recover the efficient cost of providing the service (section 7A(2) of the NEL). This will in turn limit any distortion in investment decisions by the DNSP (section 7A(6) of the NEL) and utilisation decisions by users (section 7A(7) of the NEL). The approach will also ensure that the DNSP's incentive to pursue productive and dynamic efficiencies are not distorted (section 7A(3)). Overall, JEN's proposed framework may be viewed as giving rise to a better alignment with the NEO than the AER's proposed framework.

It follows that the application of this modified framework to JEN's outsourcing arrangement with JAM and the conclusions reached from the application of this framework are more in keeping with the opex and capex criteria, the NEO and the revenue and pricing principles than the assessment that has been made by the AER by reference to its own proposed framework.

The AER should therefore accept that the price payable under the AMA—including both the base and performance margin—is consistent with the operating and capital expenditure criteria contained in clauses 6.5.6(c) and 6.5.7(c) of the Rules and may be used as the basis for JEN's forecast operating and capital expenditure for the 2011-2015 regulatory control period and the operation of the EBSS. A more detailed assessment of the compliance of JEN's forecast operating and capital expenditure for the 2011-2015 regulatory control period with the Rules is set out in the following two chapters.

7 Forecast operating and maintenance expenditure

- JEN's revised total opex is $338.2 million over 2011-2015.

- Benchmarking of JEN's opex shows that its costs compare favourably to its peers. This reflects the significant economies of scale and scope that JEN is able to benefit from through its outsourcing to a specialist asset manager, JAM.

- The AER has approved the approach taken by JEN in deriving its opex forecasts, where JEN's revealed costs provided the starting point for determining if the forecast costs are prudent and efficient. The AER proposed a number of changes to the adjustments made by JEN in its original regulatory proposal. JEN has incorporated or partially incorporated many of the AER's proposed amendments to its forecast opex. However, JEN considers that:

  – the outsourcing margin, costs of corporate activities and many of the step changes reflect prudent and efficient expenditure in accordance with clause 6.5.6(c)(1) and (2) of the Rules

  – the approach it has proposed to labour and materials escalation, and its proposal for IT scale escalation, provide realistic forecasts for the purposes of clause 6.5.6(c)(3) of the Rules.

7.1 Summary of JEN's original regulatory proposal

For its original regulatory proposal, JEN employed two methods to forecast its opex costs for the forthcoming regulatory control period:

- *base year roll-forward approach*—JEN applied this approach to over 95 per cent of its opex over the next regulatory control period.

- *specific year-by-year forecasts*—for some specific cost components, JEN determined specific year-by-year forecasts:

  – self insurance

  – debt and equity raising costs

  – step changes.

JEN proposed to return opex efficiencies totalling $54.4 million over the current regulatory control period to its customers by adopting its 2009 costs as the base year for its opex forecast.

JEN's proposed forecast opex included in its original regulatory proposal is set out in Table 7-1.

Table 7-1: JEN's original regulatory proposal forecast opex by RIN category ($ million, $2010)

Opex item	2011	2012	2013	2014	2015
Maintenance costs	22.4	22.6	22.8	23.3	22.9
Network operating costs	11.9	11.4	11.8	12.1	12.4
Billing & revenue collection	3.4	3.3	3.4	3.5	3.6
Customer service	3.8	3.6	3.7	3.8	3.9
Advertising, marketing & promotions	1.2	1.1	1.1	1.2	1.2
Regulatory	2.3	2.2	2.2	4.6	3.5
Other	17.7	17.0	17.7	18.2	18.6
GSL payments	0.0	0.0	0.0	0.0	0.0
Total	**62.6**	**61.1**	**62.9**	**66.7**	**66.1**

Note: GSL payments are positive, but due to rounding appear as zero.

7.2 Summary of AER's draft determination and decision

The AER did not approve JEN's forecast opex of $319.4 million ($2010 real) on the grounds that it did not comply with clause 6.5.6 of the Rules. Instead the AER set out its own forecasts.

Base year roll-forward approach

The AER approved the use of a revealed cost base year roll-forward approach to opex forecasting. However it did not adopt JEN's proposed base year costs and instead made adjustments it considered necessary to:

- exclude the allocation of the SP management fee paid included in JEN's enterprise support function (**ESF**) costs

- exclude certain ESF costs relating to the energy investments, investment analysis and financial strategy cost centres

- remove the commercial margin JEN pays to JAM under the AMA.

The AER approved JEN's proposal to include the difference between the ESCV's 2009 and 2010 opex forecasts as an adjustment to the base year to take it to a 2010 figure before applying escalation.

The AER approved its own scale escalation factor which it adjusted for its view of economies of scale and what it characterised as capex/opex trade-off.

The AER did not accept the labour and materials escalators jointly proposed by the Victorian DNSPs. Instead it substituted its own escalators determined by Access Economics.

Specific year-by-year forecasts

The AER did not approve JEN's specific year-by-year forecasts for self insurance, debt raising costs or most of JEN's proposed step changes.

AER required extensive adjustments to JEN's opex forecasts

The AER's draft decision required that JEN make the following amendments:[152]

- adjustments to JEN's base year costs in addition to those already identified by JEN for one-off costs and 2010 benchmark efficiency adjustment

- use of the AER's labour and material input cost escalators

- use of the AER's net scale escalation factor

- removal of JEN's proposed self insurance costs for substations - catastrophic or component failure, other assets – storms and lightning, other assets – pole fires

- use of benchmark debt raising costs of 9.8 basis points per year

- various rejected and lowered step change items totalling a reduction of $42.2 million over five years.

[152] Draft decision, p. 222.

7.3 JEN’s response to AER’s draft determination and decision

JEN provides its response to the AER’s draft decision in this section as follows:

- *updated actual base year costs*—consistent with the AER’s stated intent, JEN sets out its actual 2009 base year costs including updated one-off costs
- *base year cost exclusions*—JEN demonstrates how the excluded corporate costs, except for the SP management fee, relate to the provision of standard control services and do not constitute double counting of corporate costs
- *step changes*—JEN provides a detailed Appendix 7.2 which further details each of the rejected or reduced step change items and applies the AER’s assessment framework to demonstrate their compliance with the Rules. Section 7.3.4 provides an overview of the outcome of this review
- *escalators* – JEN sets out how it has incorporated scale escalation elements of the AER’s draft decision for network opex, applied its own scale escalation for IT opex and obtained updated expert forecasts for input cost escalation
- *specific year-by-year forecasts:*
  - *MTR cost recovery* – forecasts the unrecovered costs previously recovered through the MTR revenue control but not otherwise provided for the AER’s draft determination.

JEN has incorporated the AER’s draft decision regarding self insurance, the SP management fee and debt raising costs.

7.3.1 Summary of JEN’s revised opex forecasts

JEN has had regard to the AER’s required amendments and revised its opex forecasts for the purposes of its revised regulatory proposal.

JEN's revised opex forecast for the forthcoming regulatory control period is summarised in Table 7-2.

Table 7-2: JEN forecast opex for revised regulatory proposal ($2010 million)

Item	Forthcoming Regulatory Period				
	2011	2012	2013	2014	2015
Maintenance costs	21.3	21.9	21.6	22.1	22.6
Network operating costs	12.0	11.6	11.7	12.1	12.5
Billing & revenue collection	3.6	3.5	3.5	3.6	3.7
Customer service	3.8	3.7	3.7	3.8	4.0
Advertising, marketing & promotions	1.4	1.4	1.4	1.4	1.5
Regulatory	2.7	2.6	2.7	6.0	7.0
Other	20.7	20.0	20.3	21.0	21.7
GSL payments	0.0	0.0	0.0	0.0	0.0
Total	**65.6**	**64.6**	**64.9**	**70.1**	**72.9**

7.3.2 Updated actual base year costs

The AER's draft decision foreshadowed that JEN's base year opex costs would be updated for actual costs. It also accepted JEN's proposal to adjust its base year 2009 opex costs for:

- identified one-off costs
- the benchmark efficiency adjustment forecast by the ESCV between 2009 and 2010
- removal of alternative control services operating costs.

JEN has updated its base-year costs for 2009 actual data and applied other base year cost adjustments consistent with the AER's draft decision as set out in the following sections.

Update for actual 2009 costs

For the purposes of its revised regulatory proposal, JEN has updated its opex cost stack for full year 2009 actual data drawn from its audited regulatory accounts.

At the time of JEN's original regulatory proposal, actual cost data was not available for the full 2009 year. As a result, JEN originally estimated its actual 2009 costs using some actual costs and some estimated data as set out in Table 9.3 of its November 2009 regulatory proposal.

Table 7-3 sets out how the basis of JEN's 2009 costs has changed relative to its original proposal.

Table 7-3: Basis of JEN 2009 base year costs

Cost item	Description of source original Nov 09 proposal	Description of source revised Jul 10 proposal
JAM direct costs	2009 actual to Sep and estimate to Dec	2009 actual regulatory account data
JAM indirect costs	2008 actual escalated to 2009	2009 actual regulatory account data
JAM corporate costs	2008 actual escalated to 2009	2009 actual regulatory account data adjusted for one-off costs and provisions
JEN non-JAM direct costs	2009 actual to Sep and estimate to Dec	2009 actual regulatory account data adjusted for one-off costs
JEN corporate costs	2008 actual escalated to 2009	2009 actual regulatory account data adjusted for one-off costs and provisions

Update for actual one-off costs and provision adjustments

The update from corporate costs based on 2008 data to actual 2009 corporate costs requires JEN to also update its one-off costs. JEN originally proposed, and the AER's draft decision approved, one-off corporate costs that were based on one-off projects in 2008. All bar one of these projects were only relevant to 2008.

The AER's draft decision also required DNSPs to remove the effects of provisioning from their reported base year costs to arrive at a recurrent cost base.[153]

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[153] Draft decision, p. 242.

{c-i-c}

JEN notes that these provisions were not relevant to Jemena Limited or JEN's current business and their one-off write-off deflated JEN's reported 2009 corporate costs below recurrent levels. Failure to adjust for this in the JEN's opex forecast would erroneously understate JEN's reasonable required costs over the forecast period.

The update for actual 2009 direct JEN and JAM costs requires JEN to update its one-off costs for actuals instead of estimates. JEN provides updated actual one-off costs for each of these direct costs in Appendix 18. 3.

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Table 7-5 shows JEN's revealed actual cost along with the adjustments to determine JEN's efficient recurrent cost base.

Benchmark efficiency adjustment between 2009 and 2010

The AER's draft decision adjusted the DNSPs 2009 opex cost base for the benchmark efficiency adjustment forecast by the ESCV between 2009 and 2010.

JEN agrees with the intent of this adjustment and had proposed such adjustment in its original regulatory proposal. The adjustment is necessary to preserve even incentives properties of the EBSS. However the AER's application requires a minor amendment.

It its draft decision, the AER adjusted for the difference between the ESCV's original opex forecasts. However, the adjustment should be based on the growth-adjusted opex forecasts used in the EBSS calculation. Failure to do so, means JEN only receives EBSS growth adjustment for four of the five years. The consequence is that the EBSS won't provide even efficiency incentives for each year of the regulatory period.

JEN has corrected for this in its revised opex forecast.

Alternative control services costs

Consistent with the AER's draft decision, JEN has deducted the value of costs the AER attributes to alternative control services (**ACS**). In doing so, JEN has removed from total opex an amount that is based on a $2009 equivalent of the ACS estimated costs put forward in the revised proposal (which are in turn consistent with the intent of the AER's draft decision on ACS) and the volumes of ACS services provided.

Given the link between the estimated costs of ACS and the SCS opex, if the AER's final decision on JEN's ACS costs and prices differs from JEN's revised regulatory proposal, JEN requests that the AER provides JEN with the opportunity to make consequential changes to JEN's forecast data model. JEN needs to make these consequential changes to avoid double recovery (or under-recovery) of base year operating costs.

7.3.3 Base year cost exclusions

The AER's draft decision disallowed JEN's base year costs relating to the energy investments, financial strategy and investment analysis cost centres within the Jemena Limited ESFs. The AER concluded that JEN had provided insufficient information on these costs to demonstrate that they relate to the provision of regulated services and that they are costs which would be incurred by a prudent operator.[154]

JEN's base year costs inclusive of corporate overheads are efficient and relate to the provision of regulated services

JEN provides below additional information demonstrating that these functions relate to the provision of regulated services and represent costs that a prudent operator would incur. In particular, any prudent firm must comply with certain regulatory obligations of a corporate nature that, despite being commercial obligations, are nonetheless necessary in order to provide distribution services.

Regarding the efficiency of JEN's costs for each of these activities, JEN notes that it benefits from the economies of scale and scope within Jemena Limited's ESFs because it only incurs an allocation of costs for these items rather than the stand alone cost it would incur under a different business model. Further, PwC's expert forensic account review of the whole of business cost allocation (**WOBCA**) for JEN independently confirmed that these costs had been allocated on a justifiable causal basis.[155]

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[154] Draft decision, p. 208.

[155] JEN, *Appendix 7.3 PricewaterhouseCoopers – Independent review of whole of business cost allocation*, 30 November 2009, p. 5.

Before explaining the specifics of each of the identified ESF cost centres, JEN provides the following general observations on the AER's reasoning for rejecting these costs.

First, JEN considers it is not possible to distinguish between activities that are to the benefit of owners and those that are to the benefit of network users. Setting and levying charges for the use of a network does not benefit customers (at least in the short term), and neither does the asset owner's participation/advocacy in a price review, but these activities clearly comprise part of the activities which are undertaken in order to provide distribution services.

Similarly, investment funds are required in order to continue to provide distribution services, and this requires JEN to market itself to debt providers and to keep them informed and to provide information to equity providers. Any stand alone firm would have to do this, be it a publicly listed firm or a privately owned firm.

Secondly, the AER's rejection of the financial strategy costs seems at odds with prudent corporate practices. It is unclear how any firm could comply with reporting requirements of the Corporations Act 2001 (Cth) without having a general ledger and keeping abreast of changes in accounting standards and developing its systems accordingly. Further, JEN could not comply with the AER's own regulatory accounting requirements if these accounts could not be audited back to base accounts, and for those base accounts, in turn, not to have been externally verified and maintained in accordance with up to date accounting standards.

Thirdly, the AER's view that JEN has not shown that the cost centres are directly related to providing distribution services is not relevant in relation to *corporate overheads*. By their nature, corporate overheads cannot be allocated directly to a particular business. This is why allocations were required in the first place.

JEN provided an expert forensic account report (original regulatory proposal Appendix 7.3) from PwC with its original proposal which independently verified that the WOBCA allocations to JEN were reasonable and reflected a suitable causation basis for the allocators.[156] Further, each of these cost centres relates to distinct activities that do not duplicate one another.

Energy investments

Energy investments, also referred to as 'infrastructure investments', provides the asset owner and controller function which is integral to the prudent operation of the network and provision of standard control services. This is illustrated in the JEN

[156] JEN, *Appendix 7.3 PricewaterhouseCoopers – Independent review of whole of business cost allocation*, 30 November 2009, paragraphs 126-145.

management structure diagram in Figure 2-4 of JEN's 30 November 2009 regulatory proposal.

Figure 2-4 shows that JEN's regulated asset financial obligations, network oversight and regulatory functions are all performed within the energy investments group.

JEN notes that the energy investments cost centre which the AER draft decision rejected excludes the separate cost centres for the regulatory group, energy networks and asset owner finance. While Figure 2-4 shows that these cost centres report to the energy investments group, their costs are reported separately[157] and were not excluded by the draft decision.

Key functions of the energy investments cost centre that relate to the prudent provision of standard control services are:

- meeting with the AER and various Victorian and Commonwealth government departments and agencies regarding current and future regulatory, safety and service obligations imposed on JEN
- approving JEN's annual regulatory accounts
- administering at a senior level asset management contracts and service providers including scope and performance management
- setting JEN's network objectives for planning and maintenance purposes as detailed in the 'JEN Strategic Objectives' document provided as Appendix 9.4 in JEN's original regulatory proposal
- providing network strategy, reporting and control including strategic planning, benchmarking, business reporting
- reviewing and assessing the impact of energy and related policies on the JEN business
- developing policies and strategies for the JEN business (including AMI, climate change, demand management)
- being the point of contact and facilitating interaction with government stakeholders during emergency events

[157] These costs fed into JEN's base year opex from JAM direct costs and JAM corporate costs. This is shown in Appendix 18.3.

- monitoring and analysing economic, social, technical, regulatory data and trends for JEN

- providing resolution on escalated policy/political issues or risks.

Financial strategy

Financial strategy provides ongoing and project based services supporting JEN's financial systems. As noted above, and as with any firm, JEN must comply with the Corporations Act 2001 (Cth). JEN and Jemena Limited must maintain a general ledger and keep abreast of changes in accounting standards and reporting requirements. This involves developing, updating and maintaining the firm's finance systems.

JEN's 18 February 2010 response to the AER's 3 February 2010 questions explained JEN's need to ensure it has access to operational and fully supported financial systems, and that the financial strategy group provides these services through:

- management and maintenance of finance systems

- implementation of finance projects.

The finance strategy team employs specialist accounting and IT expertise that keeps JEN's financial systems up to date by implementing continuous improvements in these finance systems.

Various other groups, including energy investments, draw on data from these finance systems for a myriad of regulatory and service delivery purposes ranging from statutory reporting requirements through to data inputs to JEN's regulatory accounts and its RIN templates.

Finance projects also contribute to ensuring JEN's ongoing prudence in its delivery of standard control services. Key functions of this group in recent history and during the forthcoming regulatory period involve scoping and implementing financial systems improvement initiates for time writing and the 'one SAP' accounting system.

The following examples illustrate the relationship between the financial strategy team's financial projects role and the prudent delivery of standard control services by JEN:

- *One SAP* – Financial strategy's systems team are integral to implementing the new SAP accounting system. The AER's draft decision effectively approved capital expenditure to implement this system within JEN's IT capex program because this takes place at the beginning of the regulatory period and has accepted a negative IT step change for the benefits of this system, whereas the part of the operating expenditure for implementing this project was captured within the finance strategy group costs which the draft decision rejected.

- *Time writing* – The provision of accurate staff time-writing data is a key input into the WOBCA allocation method. Corporate teams within Jemena Limited are now required to provide timesheets allocating their time to different activities, clients and assets. The finance strategy team is delivering this initiative and will manage the ongoing IT systems to facilitate time writing and incorporation of time writing data into SAP systems.

Investment analysis

Budgeting and forecasting are critical inputs to the prudent administration of a distribution business. JEN has previously explained[158] that the investment analysis group provide:

- group budgeting & forecasting
- ownership of the corporate model and long term forecast
- financial modelling and project support.

While the AER's draft decision noted that 'the AER acknowledges that budgeting and forecasting and financial modelling are associated with the provision of distribution services', it concluded that JEN's allocation of investment analysis costs relate more to the provision of information for the management of Jemena Group businesses. It also noted that JEN had not provided any specific examples of the modelling support for specific projects that investment analysis provides to JEN.

JEN provides the following specific examples of modelling and other support that it receives from investment analysis:

- *Managing the development and on going monitoring of the whole of business cost allocation process and policy* – This is managing the independent export review of the WOBCA method to support JEN's regulatory proposal, ensuring the policy is correctly applied to allocate corporate costs for inclusion in JEN's annual regulatory accounts and the statutory accounts of the Jemena Group that serve as inputs to JEN's regulatory accounts.

[158] JEN, *JEN response to AER email of 3 February – Question 5*, 18 February 2010.

- *Monitoring asset valuation* – The activity involves continuously monitoring JEN's asset valuation to maintain compliance with statutory reporting requirements and accounting standards and to thereby meet JEN's obligation to monitor asset impairment.

- *Providing continuous disclosure to debt providers* – JEN forms a significant part of the Jemena Group business and therefore its corresponding debt requirement. This activity includes providing information and analysis to new and existing financial institutions that contribute to the Jemena Group's external debt requirements. JEN's allocated share of these reflects its share of corporate debt because these are allocated using JEN's fair value.

- *Maintaining credit ratings* – The Jemena Group's debt providers require it to maintain up to date credit ratings with ratings agencies. This activity involves providing ongoing information and analysis to credit rating agencies. JEN's allocated share of these reflects its share of corporate debt because these are allocated using JEN's fair value.

- *Preparing financial advice to inform JEN's capital decisions* – In addition to the budgeting and expenditure forecasts that feed into JEN's capital investment business cases which require Board approvals, the investment analysis team provides analysis of the cash flow and debt financing requirements as well as ensuring alignment with regulatory revenue allowances.

- *Maintaining the JEN financial budgeting and forecasting model* – Various groups within the JEN business rely on the JEN financial budgeting and forecasting model. This model is designed, built and continually improved by the investment analysis team. This model is an essential tool for JEN's budgeting and capital investment decision making.

- *Supporting modelling functions and activities within JEN* – The investment analysis team also provide JEN with modelling and analysis resource support in peak periods, and conduct model reviews as peer checks to ensure accuracy in JEN's financial modelling.

JEN notes that these activities are different to those funded through the AER's benchmark debt raising cost allowance. The AER's benchmark explicitly excludes internal costs of debt raising:[159]

> 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.

[159] Draft decision, p. 265.

JEN's corporate costs benchmark favourably

JEN engaged UMS as a suitably qualified independent expert to benchmark JEN's base year and forecast opex against comparable network utilities and provide an opinion on the efficiency of JEN's operating expenditure by comparative reference to JEN's network peers.

Relying upon JEN's revised base year opex, UMS benchmarked the costs of JEN's non-field activities and corporate overheads (**NFACO**) by comparing JEN's costs to the predictor it derived by reference to JEN's network peers. This analysis found JEN's NFACO costs were significantly lower than one would anticipate if relying on benchmarking to forecast JEN's costs.

UMS concluded that:

> 'Based on the indicators - Adjusted NFACO vs. Customers and Adjusted NFACO per Customer vs. Customers - overall NFACO cost is 47% lower cost than predicted levels ie, average of 37% and 57%. Hence predicted average NFACO for JEN for the base year is $57.5 Million while the relevant base year costs are $39M: a difference of $18.4 Million.'[160]

JEN considers this to be a result of the economies of scale and scope available to it through Jemena Limited. JEN's share of corporate costs allocated through the WOBCA method represents very good value for money for JEN and its customers.

Outsourcing margin

JEN's revised opex forecast is inclusive of the margin payable to JAM under the AMA. JEN's response to the AER's draft decision on outsourcing is contained in chapter 6 and Appendix 6.12.

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[160] UMS, *Jemena Electricity Networks (JEN) – Victoria AUS, Operating Expenditure Efficiency Review*, 15 July 2010, p. 50 (Appendix 6.11).

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7.3.4 Step changes

JEN originally proposed opex step changes totalling $52.9 million over five years of which the AER's draft decision approved $10.7 million. JEN proposed 61 step change items of which the AER approved 9 at JEN's proposed amount, reduced the value of 3 and rejected 46.[161]

In Appendix 7.2, JEN has reviewed its proposed step changes in light of the AER's draft decision, new information now available to JEN and the specific legal and regulatory obligations affecting JEN's operations in the next regulatory period. As a result of this review, JEN's revised opex step changes total $57.3 million over five years. These reflect JEN:

- 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.

Attachment 7.2 details JEN's revised step changes and demonstrates how these comply with the AER's step change assessment framework.

Electric Line Clearance Regulations

JEN's most significant opex step change is $10.94 million over 2011-2015 for costs associated with the Electric Line Clearance Regulation change. JEN's estimate is based on the outcomes of a joint meeting held on 14 July 2010 at the Energy Safe Victoria's (**ESV's**) offices and attended by staff from the AER, the ESV and the five DNSPs. JEN considers that at the meeting the ESV and the AER agreed that:

- in the forthcoming regulatory period distributors face material increases in the scope and volume of work required to meet their safety obligations
- the extent of the increase in scope and volume of work for each distributor will be assessed by the ESV in a timeframe that allows the AER to consider the ESV's assessment and incorporate it into the AER's final determination.

JEN requests that the AER provide it with an opportunity to revise its costs once the extent of the increase in scope and volume of work has been agreed (expected by mid August 2010).

[161] JEN withdrew three in consultation with the AER.

EDPR costs

JEN notes that, in its draft decision, the AER accepted JEN's total proposed costs of $3.5 million to be incurred in relation to opex step changes for regulatory submission costs during the forthcoming regulatory control period. These costs were based on estimated data because JEN actual 2009 costs and year to date 2010 costs were not available.

Since submitting its regulatory proposal, JEN has been able to obtain better information, based on actual reported costs for 2009 and year to date 2010 costs, as to the opex step changes required for regulatory submission costs. Specifically, JEN notes that actual costs in 2009 amounted to $3.9 million, which is significantly higher than the estimated cost of $2.2 million (the basis of the 2014 forecast). JEN also notes that a further $1.3 million had been forecast for 2015.

Because the AER is required to consider the 'actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods', JEN requests that the AER accept its revised opex step changes in relation to regulatory submission costs because they represent an updating of the 2009 base year based on better information (i.e. actual opex). JEN also notes that the provision of this further information, based on 2009 actuals, is intended to help the AER to come to a view in relation to JEN's total opex step changes.

JEN notes that it has deducted its reported 2009 EDPR costs from the opex cost base for the purpose of applying the base year roll-forward. These costs have then been added back in for 2014 and 2015.

7.3.5 Escalation

JEN's base year roll forward forecasting method involves four forms of escalation:

1. real input cost escalation
2. inflation escalation
3. scale escalation – general network
4. scale escalation – IT.

Escalation also requires weightings for each cost input. JEN has retained the weightings from its original proposal. These weights were the basis for the AER's draft decision and therefore do not require amendment.

Real input cost escalation

For its original regulatory proposal, JEN relied on material escalators from SKM and labour cost forecasts from BIS Shrapnel. JEN's material and labour cost escalators are shown in Table 7-6.

Table 7-6: JEN opex cost escalators (per cent annual change unless noted otherwise)

Escalator	2010	2011	2012	2013	2014	2015
Aluminium	18.5	7.7	6.2	6.4	6.0	5.7
Copper	16.9	1.7	-1.3	-1.8	-1.8	-1.8
Steel	22.8	9.5	4.2	1.7	1.7	1.6
Crude oil	32.3	3.0	1.8	2.3	2.2	2.4
Exchange rate ($A/$US)	0.733	0.689	0.689	0.689	0.689	0.689
Internal labour	3.84	2.43	2.63	2.73	2.63	2.43
External labour	3.04	1.93	2.63	3.03	2.53	2.33
Wood poles	3.2	3.2	3.2	3.2	3.2	3.2
Inverse of TWI and CPI	1.5	2.3	2.3	2.3	2.3	2.3
Construction costs (a)	1.60	2.53	4.34	4.57	2.73	1.22

Note (a): The draft decision appears to have quoted the SKM escalator for non-residential construction in its summary of the DNSP proposals[162] instead of the 'engineering' escalator in SKM table 4 (p. 25). JEN has inserted the correct escalator in the above table. For comparison with the draft decision, JEN has expressed the SKM engineering index as annual price changes.

In addition to the above, JEN applied the input cost escalators that SKM developed under the CPRS5 ETITE scenario.

Section 8.11 and section 8.12 describe JEN's labour and non-labour cost escalators in more detail.

Inflation escalation

JEN has escalated its opex forecasts for forecast inflation

JEN has applied forecast inflation as set out in Table 7-7. This forecast relies on the RBA's most recent monetary policy statement and the AER's method of inflation forecast extrapolation.[163]

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[162] Draft decision, Appendix K, s. K.5.5, p. 144.

[163] RBA, *Reserve Bank of Australia, Statement on Monetary Policy*, 6 May 2010, Table 14, p. 56.

Table 7-7: Forecast inflation (per cent)

Details	2010	2011	2012	2013	2014	2015
Inflation forecast	1.26	2.57	2.57	2.57	2.57	2.57

Scale escalation – general network opex

JEN's original regulatory proposal used three growth drivers (customers, peak demand and energy consumption) to calculate a scale escalation for its general network opex. JEN consolidated these growth drivers into a weighted scale escalation factor which approximated the growth in the network and resulting opex.[164] JEN based this method on that previously employed by the ESCV.

In its draft decision, the AER:

- *Gross scale escalator* – produced a new annual gross growth rate for JEN of 1.1 per cent for the period 2010-2015, using different growth drivers to JEN's reflecting: [165]
  - a composite network growth factor 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[166]
- *Economies of scale deduction* – adjusted for negative annual growth over the period of 0.6 per cent calculated as the average economies of scale proposed by CitiPower, Powercor and SP AusNet
- *Capex - opex trade-off deduction* – adjusted for negative annual growth over the period of 0.1 per cent for what the AER characterised as capex/opex trade-off.[167]

JEN has incorporated the AER's scale escalation decision with some minor amendment to the gross scale escalator. In so doing, JEN notes that:

- *Economies of scale deduction* – It is unreasonable to assume JEN can access the economies of scale available to its asset management contractor

[164] JEN, forecast data model, growth factor sheet.

[165] AER, op. cit. Table J.13, p. 109.

[166] Ibid.

[167] AER, op. cit. Table J.14, p. 109.

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. In this circumstance, failure to do so would result in JEN receiving less than its efficient cost of service.

- *Capex - opex trade-off deduction* – It is unreasonable to assume JEN can realise the AER's anticipated benefits from this trade-off if the AER does not also allow JEN its proposed step changes arsing 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. In this circumstance, failure to do so would result in JEN receiving less than its efficient cost of service.

When incorporating the AER's draft decision regarding scale escalation, JEN has relied upon:

- revised customer number forecasts independently prepared by NIEIR as set out in section 5
- annual growth in line length
- annual number of distribution transformers
- annual capacity of zone substations.

JEN has employed zone substation capacity instead of the AER's proposal for number of zone substations for its scale escalator. JEN notes that whereas the AER's draft decision refers to the South Australian distribution determination among its reasoning for this composite escalator drivers, this determination relied upon zone substation *capacity instead of numbers*.[168]

JEN notes that the number of zone substations is likely to be a less accurate indicator of growth in opex costs than aggregate capacity. Typically, operational costs, inspection costs and routine, condition and emergency related maintenance is undertaken based on both the number of discrete pieces of plant and equipment used within zone substations, and the size. For example, it is reasonable to expect a zone substation with four transformers and associated volumes of subtransmission and HV switchgear will require substantially more operation and maintenance activity compared with a single transformer site.

The use of the number of zone substations rather than the installed capacity also has the potential to bias results basis on network characteristics. Such network characteristics include:

[168] AER, *South Australia distribution determination 2010–11 to 2014–15, Final decision*, May 2010, p. 121.

- rural versus urban networks, where the customer density varies considerably)
- adopted planning criteria and design standards that dictate levels of redundancy and plant and equipment sizes.

Scale escalation – IT opex

While not making specific reference to JEN's proposal, the AER's draft decision rejected JEN's proposed gross IT scale escalation[169] in favour of its own scale escalation. Importantly, the AER still deducted the IT efficiency factor inherent in JEN's IT scale escalation factor, which it characterised as a step change.

JEN submits that this decision is erroneous as it double-deducts economies of scale as regards IT and capex-opex trade-off without providing JEN suitable recovery of its forecast IT opex.

In Appendix J of its draft decision, the AER set out its proposal to use scale escalators based on line length, distribution transformers and zone substations. It then proposed to reduce the resulting scale escalator for its view of economies of scale and for what it characterised as opex-capex trade-off.

JEN considers 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 considers IT services and systems demand is more precisely determined by:

- 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

169 This factor was set out in JEN's Forecast Data Model – Appendix 13 to JEN's regulatory proposal, 30 November 2009.

- 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.

JEN calculates its proposed gross IT scale escalation factor as a weighted IT services and systems demand based on customer categories where large- scale customers are weighted much higher than the baseline residential customers.

JEN then converts this to a proposed net IT scale escalation factor by deducting an IT efficiency factor. This factor reflects JEN's views of economies of scale likely to result from customer growth and the purchase of new tools and technologies that provide incremental IT efficiency gains each year. These benefits are indirect and are a combination of multiple small initiatives; therefore JEN has captured these through a 1 per cent forecast annual IT opex productivity gain.

The AER's draft decision deducted this gain from JEN's opex forecasts as a negative step change even though it did not provide the corresponding IT scale escalation and the AER also deducted its own view of economies of scale from the scale escalation factor it applied to JEN's opex.

Table 7-8 sets out how JEN has calculated its net IT scale escalation factor.

Table 7-8: Build up of JEN IT scale escalator

Details	Type	2011	2012	2013	2014	2015
Summary						
	residential	281,882	287,215	291,990	296,194	300,316
	small medium	27,106	27,498	27,723	27,809	27,943
	large business	1,177	1,177	1,175	1,172	1,169
	total	310,165	315,890	320,889	325,174	329,428
Percentage increase						
	residential	1.91%	1.89%	1.66%	1.44%	1.39%
	small medium	1.44%	1.44%	0.82%	0.31%	0.48%
	large business	-0.05%	0.01%	-0.17%	-0.29%	-0.22%
Weighting per customer group						
100%	residential	281,882	287,215	291,990	296,194	300,316
121%	small medium	32,798	33,272	33,545	33,648	33,811
248%	large business	2,920	2,920	2,915	2,907	2,900
	total points	317,600	323,407	328,450	332,749	337,027
Weighted growth rate		1.84%	1.83%	1.56%	1.31%	1.29%
Less 1% IT efficiency gain		1.00%	1.00%	1.00%	1.00%	1.00%
Net IT OPEX Forecast Growth		0.84%	0.83%	0.56%	0.31%	0.29%

JEN requests that IT growth be treated as a distinct case from the uniform application of growth metrics applied by the AER. JEN's net IT scale escalator provides:

- a rate of increase that reflects the relative increase in IT demands arising from growth in each customer segment
- an offset against growth increase through the productivity gains of economies of scale and the introduction of new technology tools and methods
- a net 5-year total result of 2.8 per cent in IT weighted growth at an average of 0.56 per cent per year.

JEN notes that the AER's draft decision to remove JEN's forecast IT efficiency gains cannot be retained in the final decision unless the corresponding gross IT escalator is also adopted.

7.3.6 Specific year-by-year forecasts

In this section JEN describes its opex forecasts for elements that it forecasts on a year-by-year basis. JEN does not apply the standard base year roll forward approach to these costs because either:

- base year costs are not necessarily representative of the future
- an alternative method is likely to derive a better estimate in the circumstances.

As for its original regulatory proposal, JEN forecast some specific cost components on a separate year-by-year basis. These costs include self insurance, debt raising costs and step changes. The AER rejected JEN's proposal for each of these costs. JEN's response is set out below, except for step changes, which JEN has addressed in section 7.3.4 because these are escalated as part of the base year roll forward.

JEN has also added a new specific year-by-year opex forecast relating to costs previously recovered through the MTR revenue control.

Self insurance

The AER rejected three of the six self insurance events that JEN proposed and also introduced new reporting requirements for self insured events to apply during the regulatory period. The rejected events were:

- substations – catastrophic or component failure
- other assets – storms and lightning
- other assets – pole fires.

JEN has updated its opex forecasts to reflect the AER's draft decision.

Debt raising costs

The AER considered that no new information was provided by the distributors to warrant it changing its method. It did however refine this method slightly. Its method determined benchmark debt raising costs for JEN of 9.8 basis points pa. JEN had proposed 12 basis points based on the AER's decision for NSW networks.

JEN has updated its opex forecasts to reflect the AER's draft decision.

Unrecovered MTR costs

The AER's draft determination and decision provided no recovery mechanism for JEN's transmission connection costs, internetwork charges and payments to embedded generators. JEN currently recovers these through the MTR revenue control.

These costs clearly meet the opex criteria. To ensure compliance with section 7A(2)(a) of the NEL, JEN has proposed a pass through control mechanisms for these costs in section 4.3.6. If the rule change proposal is not approved and implemented prior to the AER's final decision or the AER does not accept JEN's proposed pass through control mechanism, then JEN proposes the costs set out in

Table 4-2 be included in its opex forecast.

7.4 JEN's revised regulatory proposal

In light of the revised opex forecast set out in this chapter, JEN's revised forecast opex set out in Table 7-9.

Table 7-9: Revised forecast opex ($ million, $2010)

Opex item	2011	2012	2013	2014	2015
Maintenance costs	21.34	21.95	21.61	22.09	22.61
Network operating costs	12.02	11.55	11.73	12.12	12.49
Billing & revenue collection	3.59	3.45	3.50	3.62	3.73
Customer service	3.81	3.66	3.72	3.84	3.96
Advertising, marketing & promotions	1.41	1.36	1.38	1.42	1.47
Regulatory	2.74	2.63	2.67	5.99	6.99
Other	20.71	19.97	20.30	21.01	21.66
GSL payments	0.02	0.02	0.02	0.02	0.02
Total	**65.6**	**64.6**	**64.9**	**70.1**	**72.9**

7.5 Compliance with the Rules

JEN's revised opex forecasts are made on a reasonable basis and have been developed to comply with the operating expenditure objectives and operating expenditure criteria and to address the operating expenditure factors specified in the Rules.

7.5.1 Operating expenditure objectives

Notwithstanding where JEN has incorporated the AER's draft decision, JEN has established its revised opex forecasts to comply with the operating expenditure objectives specified in the Rules by:

- examining its current base year costs incurred in meeting current service level and regulatory obligations
- assessing the sufficiency of its current compliance with regulatory obligations to identify step changes for corrective actions
- assessing foreseeable new or changed obligations and changes to the operating environment that will affect its operating activities and costs to identify step changes

- incorporating escalation for expert determined demand growth and input cost escalation.

Table 7-10 summarises how JEN has complied with the operating expenditure objectives.

Table 7-10: Operating expenditure objectives

Operating expenditure objective	Rule	JEN actions to ensure compliance
Meet or manage the expected demand for standard control services	6.5.6(a)(1)	JEN has employed the AER's scale escalator. JEN has proposed a specific scale escalation factor for its IT opex, which is explained in section 7.3.5.
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.6(a)(2)	JEN has assessed its current compliance (and associated base costs) as well as assessing corrective actions and additional new obligations (and associated step changes). JEN has discussed its proposed step changes in detail in Appendix 7. 2.
Maintain the quality, reliability and security of supply of standard control services	6.5.6(a)(3)	JEN's base year opex is derived from the current levels of expenditure incurred by JEN to meet this objective. JEN's activities are guided by its comprehensive COWP and NAMP, which set out the approach JEN takes to operating and maintaining its assets. JEN has provided detailed information in Appendix 7.2 in relation to the step changes that are required as a result of changes in JEN's operating environment, or will provide additional benefits to customers or otherwise meet the opex criteria.
Maintain the reliability, safety and security of a distribution system through the standard control services	6.5.6(a)(4)	JEN's base year opex is derived from the current levels of expenditure incurred by JEN to meet this objective. JEN's activities are guided by its comprehensive COWP and NAMP, which set out the approach JEN takes to operating and maintaining its assets. JEN has provided detailed information in Appendix 7.2 in relation to the step changes that are required as a result of changes in JEN's operating environment or will provide benefits to customers or otherwise meet the opex criteria.

7.5.2 Operating expenditure criteria

The AER recognises that JEN's current levels of opex provide a starting point for determining if the opex forecasts are prudent and efficient. In the current regulatory period, JEN has had an incentive to minimise its costs overall to maximise its commercial position. This incentive has been created by the fixed opex allowance and price cap that the ESCV provided to JEN in 2005, and has been further supported by the operation of the ESCV's efficiency carry over mechanism.

The AER has specified particular adjustments made by JEN which it does not approve. JEN assumes that, as required by clause 6.12.3(f) of the Rules, these are the only changes which the AER considered should be made to establish that JEN's opex forecasts meet the opex criteria.

JEN has addressed each of these issues in this revised regulatory proposal. It has accepted a number of the AER's proposed amendments. In respect of the other item it has discussed why it considers the following expenditure to be prudent and efficient:

- corporate costs (see section 7.3.3)
- outsourcing margin (see chapter 6 and Appendix 6.12)
- step changes (see section 7.3.4 and Appendix 7.2).

Forecast methods reflect realistic expectations of demand and input costs

JEN's application of the base year roll-forward approach to the majority of JEN's opex forecast, and its year-by-year forecasts of other specific costs is consistent with the AER's approach and is reasonable and based on the best information available, including:

- Jemena's internal cost information and allocation method, which PwC has verified as reasonable
- reliable expert reports from NIEIR, SKM, BIS Shrapnel and Econtech that provide reasonable demand forecasts and estimates of cost escalators and which address specific matters raised by the AER in its draft determination and draft decision. These include: providing revised economic growth and population assumptions, delaying the impact of the CPRS and recognising the termination of the home insulation scheme. NIEIR has also revised a number of policy impacts assumed in its original forecasts to incorporate better or more recent information. Regarding materials escalation, SKM has provided an updated report which addresses a number of requirements of the draft decision. These include using the AER's foreign exchange

forecasts, and making no allowances for carbon, wood poles or a trade-weighted index. Additionally, JEN has obtained updated labour cost escalator reports from BIS Shrapnel and KPMG Econtech which reflect the latest available forecasts.

7.5.3 Operating expenditure factors

The Rules set out the operating expenditure factors which the AER must have regard to when deciding whether or not to approve JEN's revised opex forecast. Table 7-11 summarises points JEN considers relevant to these factors.

Table 7-11: Operating expenditure factors

Operating expenditure objective	Rule	JEN comments
the information included in or accompanying the building block proposal	6.5.6(e)(1)	JEN has provided a comprehensive regulatory proposal supported by extensive appendices, financial models and RIN templates as well as an extensive initial response to the draft determination and decision. JEN has provided further updated and developed information with this revised proposal to address issues raised by the AER in its draft decision.
submissions received in the course of consulting on the building block proposal	6.5.6(e)(2)	
analysis undertaken by or for the AER and published before the distribution determination is made in its final form	6.5.6(e)(3)	
benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period	6.5.6(e)(4)	JEN provides the UMS benchmarking report in Appendix 6.11.
the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods	6.5.6(e)(5)	JEN has provided its actual historic expenditure to the AER. As noted above, JEN has adopted its expenditure per its 2009 audited regulatory accounts as the starting point for developing its opex forecasts consistent with the AER's approved approach.

Operating expenditure objective	Rule	JEN comments
the relative prices of operating and capital inputs	6.5.6(e)(6)	JEN relies on lifecycle management planning for each asset, which considers all strategies and options over the entire asset life from planning to disposal to deliver the lowest long-term cost. Lifecycle management focuses on ensuring effectiveness and efficiency in maintenance (opex) and replacement (capex) of the network assets based on reliability centred maintenance analysis and considers issues of safety, cost, risk and reliability. Together JEN's IT capex, opex and step change forecasts provide a good example of this balancing. The efficiencies that JEN has achieved through this IT planning and forecasting rely upon the AER's wholistic assessment of these interdependent expenditures. Additionally, JEN has relied upon the same input cost escalators for capex and opex.
the substitution possibilities between operating and capital expenditure	6.5.6(e)(7)	JEN has assessed these opportunities and has proposed: an enhanced asset inspection program (opex) to complement the asset replacement strategy (capex) several IT capex projects that provide for corresponding savings in IT opex costs over the forecast period.
whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period	6.5.6(e)(8)	All significant proposals to commit funds are subject to an economic evaluation. All realistic options are included in the analysis. All costs, savings (both capital and operation/maintenance) and revenues relevant to each option are included in evaluations. These revenues include an assessment of the impact of the STPIS.

Operating expenditure objective	Rule	JEN comments
the extent the forecast of required operating expenditure of the Distribution Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms	6.5.6(e)(9)	As discussed in section 6 and Appendix 6.12, JEN has established outsourcing arrangements that reflect prudent commercial terms.
the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives	6.5.6(e)(10)	JEN's base costs include costs for avoided network costs paid to the Somerton distributed generator. JEN proposes to continue these network support arrangements until their expiry in Oct 2010. There are seven embedded generators inter-connected to the network – Somerton Power Station in Somerton, Brooklyn Landfill in Brooklyn, Bolinda Landfill in Broadmeadows, Austin Hospital in Heidelberg, LaTrobe University in Preston, Mini Hydro in Preston and Australian Paper in Fairfield. In forecasting peak demand for zone substations with embedded generation, it is assumed that the generators are running at peak load periods unless otherwise specified. JEN publishes opportunities for non-network solutions in its annual planning reports and invites non-network solution proponents to contact JEN. These documents are published in order to provide transparency and information to the wider energy industry, with a specific objective of seeking opportunity for non-network solutions to defer the need for network investment.

JEN's opex benchmarks favourably

JEN engaged UMS as a suitably qualified independent expert to benchmark JEN's historic and forecast operating expenditure against comparable network utilities and provide an opinion on the efficiency of JEN's operating expenditure by comparative reference to JEN's network peers. The UMS report is provided in Appendix 6.11.

UMS analysed JEN's historical, base year and forecast operating expenditure using a number of methods. The costs analysed were inclusive of the commercial margin paid by JEN to JAM. UMS used both publicly available information and proprietory UMS databases to benchmark JEN's opex costs using a range of key indicators.

UMS concluded that:

> 'Based on our benchmarking of Jemena Electricity Networks' (JEN) historic, base and forecast operating expenditure (Opex), we believe that JEN's spend levels are efficient based upon better than industry average performance along a wide array of key performance and benchmark indicators.'[170]

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[170] UMS, *Jemena Electricity Networks (JEN) – Victoria AUS, Operating Expenditure Efficiency Review*, 15 July 2010, p. 4 (Appendix 6.11).

8 Forecast capital expenditure

- JEN is facing difficult challenges with a significant reduction in the surplus network capacity of the past, increases in peak demand from the growth in air-conditioning, and as increasing volumes of network assets approach the end of their lives, JEN must escalate its replacement of assets before performance deteriorates, safety is compromised and costs escalate. These challenges coupled with essential business expenditure have driven JEN's revised capital expenditure (**capex**) forecasts of $620.7 million over 2011-2015.

- JEN's revised capex forecast is supported by detailed costing and analysis for projects that have further progressed through JEN's capex gating process since JEN's original regulatory proposal. This work addresses the AER's and Nuttall Consulting's (**Nuttall**) concerns of scope and cost optimisation set out in the AER's draft decision and provide a firm basis for the AER to conclude JEN's capex forecast is efficient and prudent in accordance with clauses 6.5.7(c)(1) and (2) of the Rules. JEN also notes that its revised demand forecasts and labour and material escalators used in developing its capex forecast reflect a realistic expectation in accordance with clause 6.5.7(c)(3) of the Rules.

- JEN's revised forecast capex addresses the following to enable JEN to meet capex obligations set out in clause 6.5.7(a) of the Rules:

  – arrest of the declining asset condition mainly resulting from excessively low renewal rates in the previous and current regulatory control periods

  – reduce asset utilisation to levels that restore the supply interruption, security of supply and public safety risks to prudent levels consistent with clause 6.5.7(c)(2) of the Rules

  – connect new customers in identified growth areas in accordance with clauses 6 and 7 of the JEN's Electricity Distribution License

  – comply with a range of changes to existing statutory and regulatory obligations, and new obligations

  – meet the challenges of the external operating environment including more extreme weather conditions

– maintain non-network IT.

- In its draft decision, the AER stated that the historic accuracy of the Victorian DNSPs' capex forecasts was relatively poor.[171] However, based on benchmarking the AER concluded that actual capex for 2006–2008 is efficient.[172] The AER's consultant, Nuttall, concluded that none of the DNSPs have adequately demonstrated that their proposed increases beyond historical levels is prudent and efficient.[173] Therefore, in its draft decision the AER set JEN's forecast capex over 20011–2015 based on historical spend over 2006–2008.

- The AER's draft decision on capex allowance is not sufficient to enable JEN to meet these requirements. The AER's draft reduced regulatory allowance will result in further decline in asset condition and increased security of supply risks over the forthcoming regulatory control period.

8.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN's proposed forecast capex of $669.2M over the forthcoming regulatory control period. Its forecast capex aimed to meet the:

- capex objectives set out in clause 6.5.7(a) of the Rules

- requirements of sections 4, 5, 7 and 8 of the Victorian Electricity Distribution Code (**EDC**)

- requirements of sections 6 and 7 of JEN's Electricity Distribution License (**EDL**)

- forecast demand

by striking an appropriate balance between operational and maintenance expenditure risk, and maintaining current reliability of supply.

JEN's original forecast capex was based on JEN's Network Asset Management Plan (**NAMP**)[174] and Information Technology Plan (**ITP**). It provides for a capital

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171 Draft decision, p. 285.

172 Draft decision, p. 285.

173 Nuttall Consulting, *Capital Expenditure Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 11.

174 Supported by numerous strategic planning papers, lifecycle management plans, business cases and annual work plans.

works program that enables JEN's network and IT to operate at a prudent level of risk consistent with clause 6.5.7(c)(2) of the Rules.[175]

With the expected level of demand and new connections together with anticipated climate change effects, JEN proposed that it can maintain its current levels of opex and unplanned outages only if it makes further investments in new capacity, network reinforcement and in replacing aged assets; that is, the need to arrest the impact of deteriorating network performance due to deteriorating asset condition with continuing network capital investment. An extensive review and analysis of JEN's assets leading up to its November 2009 submission took account of JEN's demand and customer growth, the age of its assets, and their impact on continuity of supply.

JEN also stated that it intends to implement new information systems to attain efficiency and capability standards consistent with good industry practice[176] and to meet the increasing requirements of the wholesale and retail electricity market. An extensive assessment has found that the life and usefulness of JEN's information technology infrastructure and applications are coming to an end after many years of service.

Accordingly, JEN proposed to invest a total of $669.2 million in its network and information technology over the next period. Major proposed new projects include:

- *Four new zone substations* – JEN will procure land and construct new zone substations in Broadmeadows South, Craigieburn, Alphington and Tullamarine to maintain prudent levels of asset utilisation in the face of increasing customer numbers and increasing demand per-head.

- *Distribution substation augmentations* – JEN will augment over 1,000 distribution substations to ensure current performance is maintained amid growing customer demand and increasing weather severity.

- *Asset replacement programs* – JEN will increase the volume of assets replaced, in the areas of poles, pole tops, overhead conductors, underground cables, zone substation transformers and circuit breakers, to replace end-of-life assets before they pose significant risks to health and safety and impact on reliability of supply.

- *Major IT projects* – JEN will undertake extensive systems investment including replacing its SAP enterprise asset management system, building a

175 In this context, JEN considers what is prudent in terms of (1) avoiding the risk of property damage or personal injury / death (that could result from declining asset condition or increased utilisation) and (2) avoiding the risk of supply interruption (that could result from a declining asset condition or increased utilisation).

176 Victorian EDC, section 3.1.

production and a disaster recovery data centre and establishing a distribution management system.

JEN’s plans also include many smaller programs and projects including those aimed at improving the reliability of supply to worst performing areas, and remedying the functional obsolescence of IT assets to ensure they continue to operate safely and reliably.

JEN’s annual forecast capex included in its original regulatory proposal for regulated standard control services (including customer contributions), as categorised into key regulatory categories is shown in Table 8-1.

Table 8-1: Original regulatory proposal forecast capex ($ million 2010)

Details	2011	2012	2013	2014	2015	Total
Reinforcements	56.7	68.9	68.7	67.2	65.5	327.1
Reliability & quality maintained	38.0	35.9	34.9	40.5	43.5	192.7
Reliability & quality improvements	0.0	0.0	0.0	0.0	0.0	0.0
Environmental, safety and legal obligations	4.1	6.9	6.2	4.6	4.1	26.0
SCADA & Network Control	0.8	1.2	1.2	0.3	0.0	3.6
Total network	**99.6**	**112.9**	**111.0**	**112.7**	**113.2**	**549.4**
Non-network – IT	20.2	21.1	17.2	6.6	6.8	71.9
Non-network - other	19.8	9.4	7.8	4.6	6.3	47.9
Total non-network	**40.0**	**30.5**	**25.0**	**11.2**	**13.1**	**119.8**
Total forecast capex	**139.6**	**143.4**	**136.0**	**123.9**	**126.3**	**669.2**

Note: Reinforecment capex includes gross customer initiated capex.

In its original regulatory proposal JEN submitted a forecast of customer contributions based on a fixed percentage of forecast customer initiated capex. The percentage was based on historic customer initiated capex and historic customer contributions for the period 2006 to 2008. JEN included customer contributions from standard customer connections in its forecast.

8.2 Summary of AER's draft determination and decision

The AER's draft determination and decision provided that, in order to make JEN's regulatory proposal acceptable to the AER, JEN would be required to amend its regulatory proposal with regard to its forecast capex.

In arriving at its draft decision, the AER relied on the following approaches to assess JEN's forecast capex:

1. review of supporting documentation
2. benchmarking of efficient costs
3. historic spend over 2006-2008
4. models to forecast renewal spend
5. high level assumptions about the level of risk implied by asset ageing.

The AER's consultant, Nuttall, noted:

- that none of the DNSPs adequately demonstrated that their overall proposed expenditure increases can be considered prudent and efficient[177]
- "as the plans advance through the DNSPs' capital governance processes significant reductions will occur, resulting in a) the deferral of some projects, b) the selection of more efficient solutions, and c) the decision not to undertake certain projects at all."[178]

In general, the AER's reliance on the above approaches led the AER to conclude that JEN's forecast capex did not meet the Rule requirements. In these instances the AER has placed significant reliance on the revealed cost approach[179] and substituted JEN's 2011-2015 forecast capex with revised forecasts based on JEN's historical spend over 2006-2008.

In rejecting JEN's proposed capital expenditure for the forthcoming regulatory control period, the AER:

- reduced JEN's proposed $327.1 million for reinforcements to $198.2 million on the basis that JEN will defer expenditure throughout the period, reducing

177 Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 11.

178 Ibid, p. 11.

179 Draft decision, p. 288.

spend against its forecast and maintaining the current actual expenditure trend

- reduced JEN's proposed $192.7 million for reliability and quality maintained to $73.6 million again on the basis that JEN will defer expenditure throughout the period, reducing spend against its forecast and maintaining the current actual expenditure trend

- accepted JEN's proposed nil expenditure on reliability and quality improvements

- slightly reduced JEN's proposed $26 million on environmental, safety and legal obligations to $25 million on the basis that there are no changes in obligations and therefore no requirement for additional expenditure

- accepted JEN's proposed $3.6 million on SCADA and network control

- reduced JEN's proposed $71.9 million on non-network IT to $51.3 million on the basis that JEN will deliver the first three years forecast expenditure over the five year period and defer the remaining two years into 2016-2020

- reduced JEN's proposed $47.9 million for non-network other to $18.1 million on the basis that JEN's planned Broadmeadows project will not proceed given that a business case has not been approved.

8.3 JEN's response to the AER's draft decision

8.3.1 Impact of AER's draft decision on service outcomes

The AER's draft decision on capex allowance is not sufficient to enable JEN to meet the capex objectives set out in clause 6.5.7(a) of the Rules. The AER's draft reduced regulatory allowance will result in further decline in asset condition and increased security of supply risks over the forthcoming regulatory control period.

JEN has examined in detail the impacts on service outcomes of maintaining its network expenditures at historical levels. The examination is based on the impact on service outcomes that JEN's customers expect, JEN's legal obligations and on JEN's duty of care obligations in running its business. In summary these are:

- *Reliability of supply* – reliability of supply is the key service performance that customers require. The intent is to maintain reliability of supply at current levels.

- *HV injections* – caused when higher voltage assets contact lower voltage assets, HV injections can cause extensive damage to customers' electrical installations. The intent is to reduce the incidence of HV injections to a minimum.

- *Fire starts* – electrical energy flowing to ground from failed assets or sparking can cause fires. The intent is to reduce the incidence of fire starts to a minimum.

- *Physical damage* – Failed poles, pole tops, and conductors can result in damage to street assets, fences, motor vehicles etc. The intent is to reduce the incidence of damage to a minimum.

- *Public safety* –The risk of injury to the public is directly proportional to the number of events, with fallen LV conductors representing the greatest risk of electrocution and contact with falling HV conductors representing the greatest risk of death. The intent is to reduce the risk of harm to the public to a minimum.

Table 8-2 shows the impact of the AER's draft decision on JEN's service outcomes over 2011-2015 and the cost to the community of non supply of electricity resulting from decreased reliability and safety, and increased asset failures. The impact is determined based on continuing with current period spend which is the basis of the AER's draft decision.

Table 8-2: Impact of AER's draft decision on JEN's service performance and community costs ($ million)

Assets	Type of impact	Potential impact of AER's draft decision on JEN's service performance	Impact community costs
Poles	Reliability, HV injections, fires, physical damage, public safety	SAIDI increase of 2.3 minutes, SAIFI increase of 0.077	5.8
Pole tops	Reliability, HV injections, fires, physical damage to third parties, public safety	SAIDI increase of 131 minutes, SAIFI increase of 1.015	153.3
Conductors	Reliability, fires, public safety	SAIDI increase of 1.6 minutes, SAIFI increase of 0.006	2.1
Underground cables	Repair costs, reliability, public safety	SAIDI increase of 4.33 minutes, SAIFI increase of 0.072	2.4
Zone substation	Reliability	SAIDI increase of 11.1 minutes,	4.0

Assets	Type of impact	Potential impact of AER's draft decision on JEN's service performance	Impact community costs
transformers		SAIFI increase of 0.049	
Zone substation circuit breakers	Reliability	SAIDI increase of 11.7 minutes, SAIFI increase of 0.088	4.7
Total community costs over 2011-2015			**172.3**

The detailed calculations for each asset type are included in the supporting business cases and stratgeic planning papers in Appendices 8.10 to 8.38.

The above table shows that the AER's draft decision is estimated to increase SAIDI by 159.9 minutes over 2011-2015 (32 minutes SAIDI per annum) at a total community cost of $172 million. JEN believes the cost of its proposed increase in its capex program included in its original regulatory proposal more than offsets the expected community cost of the AER's draft decision.

8.3.2 Actual/estimated costs 2006-2010

JEN accepts that the AER must have regard to forecast and actual spend during previous periods as set out in clause 6.5.7(e)(5) of the Rules but notes that it is one of 10 factors the AER must consider. JEN notes that the AER stated in its draft decision that "historic spend cannot completely determine future requirements"[180] which supports this view. JEN also notes that actual capital expenditure during the current regulatory control period does not support any finding by Nuttall or the AER that JEN has substantially underspend against its capital expenditure allowance. In fact, the opposite is true.

Pursuant to clause 6.5.7(e), the AER is also required to have regard to the information provided by JEN accompanying its building block proposal. JEN has provided detailed information in both its original proposal and in this revised proposal to support its forecast capital expenditure. JEN impresses upon the AER the requirements of the Rules to have regard to the information provided by JEN and, more fundamentally, to start its assessment process on the basis of this information. JEN is concerned that, in the final decision, the AER (and Nuttall) has given undue consideration tohistorical costs over 2006-2008, and insufficient consideration to JEN's proposal in assessing JEN's proposed forecast capex. To the extent this is repeated in the final decision, JEN considers that this will give rise to significant error on the part of the AER – of both a procedural and substantive nature.

180 Draft decision, p. 120.

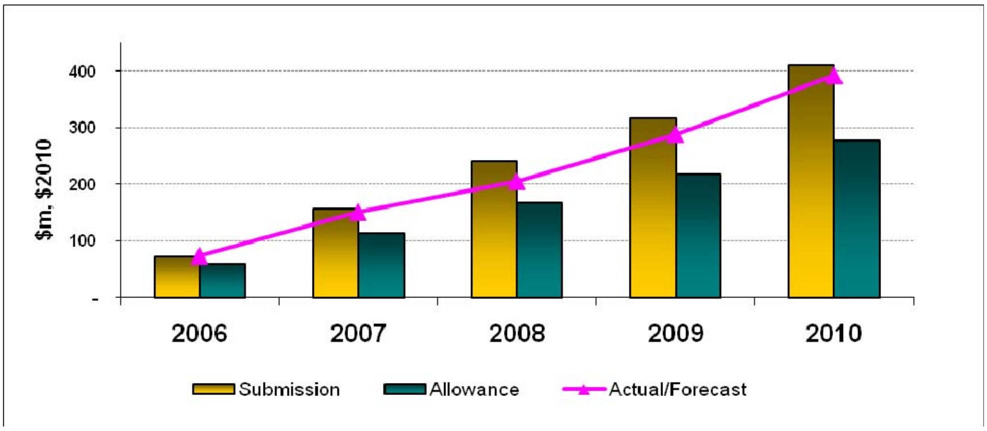
Table 8-3 shows JEN's historical and estimated spend for the current regulatory control period compared with the ESCV allowance.

Table 8-3: JEN actual/estimated gross capex compared with ESCV allowance

Item	2006	2007	2008	2009	2010	Total
JEN forecast	72.6	83.8	84.5	76.3	93.1	410.3
ESCV allowance	60.2	52.6	55.3	49.7	58.5	276.3
Actual/estimated spend	72.1	76.1	54.0	83.1	99.2	384.5
Difference between ESCV allowance and actual spend	**11.9**	**23.5**	**-1.3**	**33.4**	**40.6**	**108.2**

Figure 8-1 shows JEN's cumulative historical and estimated spend for the current regulatory control period compared with its 2005 forecast and the ESCV allowance.

Figure 8-1: Comparison of cumulative capex over 2006-2010



In section 8.6.2 of its draft decision, the AER has completed trend analysis for the aggregate of the Victorian DNSPs which shows that actual capex over the current regulatory period is significantly lower than the forecasts made by the businesses in 2005. Whilst that might be true for other DNSPs, Table 8-3 and Figure 8-1 demonstrate that JEN is expecting to close to its 2005 forecast (estimated spend of $388.6 million over the current regulatory control period is only slightly below JEN's 2005 proposed capex of $410.3 million ($2010)). In addition, they show that JEN is expecting to spend significantly more than the ESCV allowance over the current regulatory control period (gross capex of $388.6 million compared with ESCV allowance of $276.3 million in $2010).

Drivers and implications of historic trends

JEN notes 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. If the regulator continues to adopt the approach (effectively) that its own assessment in previous regulatory control periods is correct, rather than conducting a fresh assessment, a 'vicious cycle' will ensue whereby expenditure is continually deferred.

JEN considers that collectively the capex factors in the Rules seek to avoid this cycle and that excessive reliance on any one factor should be avoided.

Specific concerns with AER's trending method

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. In addition, as for a within year program, a program within a five year regulatory period tends to increase towards the end of the period (year) as the program is fully implemented. JEN believes that 2009 and 2010 are more reflective of JEN's current activities and demonstration of JEN's ability to deliver. Should the AER continue to rely on using historical spend as the primary basis for setting JEN's forecast capex, JEN requests that it does so relying on 2009 actual and 2010 estimated capex.

Further, JEN notes that while trends can be one helpful factor when assessing overall capex, they are not useful when assessing capex on a disaggregated category level basis.

Other concerns

JEN is not aware of an energy regulator in Australia that has assessed the prudency and efficiency of a service provider's forecast capital expenditure by sole reference to historical expenditure, or that has then proceeded to set an allowance for capital expenditure for significant capital expenditure categories soley on the basis of a historical trend. Unless there is clear evidence to demonstrate that historical capital expenditure is a good predictor or indicator of future capital expenditure – an approach that sets a capital expenditure allowance by reference to a historical trend is obviously inappropriate. There is no evidence (and the AER has not put forward any evidence) which would support a conclusion that historical expenditure in categories such as reinforcement and reliability and quality maintained provides the best, or indeed any, indication of prudent and efficient capital expenditure in these categories over the forthcoming regulatory period.

JEN considers that it has been unfairly discriminated against as a consequence of Nuttall's finding that the "individual Victorian DNSPs appear reasonably efficient when compared to interstate DNSPs".[181] By virtue of this conclusion, in assessing JEN's proposal, Nuttall starts from an assumption that historic levels of capex are efficient and that JEN must then justify why its forecasts depart from historical levels. This is at odds to every other energy regulatory process of which JEN is aware. Even when the AER has found that a service provider may not necessarily have been operating at a relatively efficient level, the AER has not put these service providers to a test that requires them to justify any departure from historical capital expenditure levels – a test which is completely inconsistent with the propose-respond decision-making framework for capital expenditure.

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 Rules. The Rules are straightforward – they require the AER to start with the service provider's proposal and assess the proposal by reference to the capital expenditure criteria. To the extent the AER is not satisfied that the service provider's proposal reasonably reflects the capital expenditure criteria, the AER may then go on to substitute an amount, however this 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 Rules. The Rules do not require a service provider 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. In this regard the AER's approach is inconsistent with the Rules and is in error (see also section 8.16.1).

JEN notes that, in making its original regulatory proposal, JEN carefully considered its decision to put forward a capex forecast for 2011 to 2015 that involved a significant increase in historic spend. This decision was not taken lightly, {c-i-c}

JEN's response to the AER's draft decision on the categories of capex is set out below.

[181] Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 27.

8.4 New customer connections

8.4.1 Summary of AER's draft determination and decision

The AER found that insufficient data existed to set a reliable benchmark for expenditure in this category.[182]

The AER has amended JEN's gross customer connection capital expenditure forecast to remove expenditure related to routine connections (see chapter 2 for JEN's response to the AER on service classification).

In its draft decision the AER noted that an issue had arisen in relation to customer contributions for connection assets applied under the Victorian Electricity Industry Guideline 14 and how the AER applies X factors under the Rules.[183] The AER also noted that X factors can lead to significant changes in the incremental revenue component used in the calculation of new customer contributions.[184]

As a result of these observations the AER rejected JEN's customer contribution forecast in its draft decision. The AER has used historical customer contribution levels (in percentage terms) for JEN as a place-holder pending JEN's revised proposal of customer contribution figures calculated in accordance with the Victorian Electricity Industry Guideline No. 14.[185]

The AER also amended the customer contribution forecast to remove contributions related to routine connections.[186]

8.4.2 JEN's response to AER's draft determination and decision

JEN has amended its forecast customer contribution model to reflect the AER's draft decision. In particular, JEN has:

- updated its gross customer connection capex based on revised customer number forecast by NIEIR (see chapter 5) and business activity forecast by the Construction Forecasting Council (**CFC**). This has resulted in an increase of customer connection capex compared with JEN's November 2009 regulatory proposal

- removed the customer contributions related to routine connections and revised its forecasts to accurately reflect the operation of Guideline No 14.

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182 Draft decision, p. 311.

183 AER, op. cit. p. 305.

184 Ibid.

185 AER, op. cit. p. 308.

186 Ibid.

JEN notes that its forecast customer contributions are driven by the final X factor. To the extent that the AER approves an X factor different from that proposed by JEN in section 18.3.1, JEN should be given the opportunity to revise its forecast customer contributions accordingly.

8.5 Reinforcement

8.5.1 Summary of AER's draft determination and decision

In its draft decision, the AER:

- considered that greater emphasis should have been given to historical expenditure as a basis of forecast expenditure[187]
- sought advice from ACIL Tasman on the reasonableness of JEN's proposed maximum demand forecasts. ACIL Tasman's assessment was that JEN had over forecast its maximum demand. The AER determined a revised maximum demand forecast – this is contained in Table 5.29 of its draft decision
- considered that the timing of major projects proposed by JEN was heavily reliant on the judgement of planning engineers, and that JEN did not adequately provide a clear link between this judgment and the economic efficiency of its forecasts
- considered that JEN's bottom up build of projects did not adequately take account of the further detailed analysis and refinement of projects that leads to the actual projects that are required and undertaken
- agreed with and adopted Nuttall's recommendations to allow a proportion of JEN's proposed expenditure based on its weighted probability analysis. The AER applied Nuttall's recommended 38 per cent figure to JEN's proposed direct reinforcement costs, profiling expenditure with the recommended annual growth rate of 7.4 per cent.

8.5.2 JEN's response to AER's draft decision on approach

JEN believes that the "average weighted probability" approach used by Nuttall and wholly adopted by the AER arguably does not attempt to assess proposed expenditure against the capex objectives or capex criteria. Nuttall's assessments were explicitly stated not to be aimed at assessing whether or not specific proposed projects and the associated costs could be considered prudent and

[187] Draft decision, p. 336.

efficient.[188] Nuttall expresses some generalised high-level concerns about the refinement of projects as they proceed through the capital governance processes.

In failing to examine the proposed capital program against the capex objectives, and the capex criteria, JEN believes that Nuttall's approach also does not have adequate regard to the forward-looking nature of the capex objectives and criteria. In this regard, JEN notes that Nuttall (and hence the AER) has based its assessments on the assumption that historical actual capital expenditure represents the standard for efficient expenditure.[189]

JEN believes that it is good industry practice to review future risks, network condition (including utilisation) and the potential impact on safety and performance in order to develop its future capital plans. Historical expenditure is only an indication of future expenditure if there are no new business or operational risks or change in standards or expectations. JEN must take into consideration a range of new and changed risks and requirements. To assume the future capital requirements will be simply an extension of the past will obviously lead to wrong safety and performance outcomes for the customers and the community.

JEN also notes that the approach adopted by Nuttall and the AER in substituting JEN's capex forecasts does not appear to be consistent with clause 6.12.3(f) of the Rules, in that the substitute amount or value is not determined on the basis of JEN's regulatory proposal or amended from its regulatory proposal only to the extent necessary to enable its approval in accordance with the Rules. JEN requests that the AER consider this when making its final determination.[190]

8.5.3 JEN's response to the AER's draft decision on technical matters

To address the AER's concern that further optimisation of project scopes and timings will occur as the proposed reinforcement projects go through the JEN capital governance process, JEN has developed the following supporting documentation:

- business cases for all significant near term projects (2010-11 and 2011-12) which provide project justification including detailed cost/benefit analysis of

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188 Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 50.

189 Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 10, which states 'it was agreed with the AER that our capex review would be approached in the following manner: recent actual capital expenditure can be considered to reasonably represent the efficient cost base…'.

190 Clause 6.12.3(f) provides that the AER can only substitute an amount for that proposed by the DNSP if this amount is determined on the basis of the DNSP's regulatory proposal, and amended from this basis only to the extent necessary to enable it to be approved in accordance with the NER.

various options, and represents JEN’s management approval for the delivery of the projects

- strategic planning papers for significant projects in the outer years which provide the link between asset management plan and gate 1 document. The strategic planning papers focus on the high level strategic plan for a particular geographic region over 2011-2015, identify the issues, assess options, determine optimal timing and budget cost for the recommended option to be included in the five year budget.

JEN’s response to comments made by Nuttall in its review is set out below.

Preston / East Preston conversion

Nuttall has not provided the reasons behind its assessment that “the project is mainly age driven, but it does not appear that assets require replacement at the proposed time. Further analysis will result in more optimal timing and likely deferral of some elements.”[191]

In its November 2009 submission, JEN provided the AER with a copy of the Preston Area Electricity Network Strategy 2008. The strategic plan outlines the drivers for the project being age and demand growth driven. As demand growth continues in the area, the paper shows that it is not economical to continue to develop the 6.6kV assets or to replace aged assets like-for-like. Conversion of the distribution voltage to the modern-day standard of 22kV will provide capacity for future growth. The conversion comprises of a number of stages, with some stages already undertaken in this current regulatory control period.

JEN is committed to this strategic project and notes that a number of the early stages have already taken place according to the strategic plan.

JEN also notes Nuttall’s comment that ‘Jemena’s cost for the Preston projects is on the high side of a reasonable range’. JEN has requested further information about this assertion in a letter to the AER on 29 June 10. JEN has received advice from the AER on 16 July 2010 and will make a detailed response as soon as practicable.

Pascoe Vale transformer upgrade

Nuttall asserts that:

> ‘the load at risk is not sufficient to justify this project. There is also not sufficient evidence to suggest that alternatives have been fully considered.’[192]

[191] Draft decision, Table 8.22, p. 325.

[192] Draft decision, Table 8.22, p. 325.

In response to Nuttall's criticism, JEN has developed a business case for the Pascoe Vale transformer upgrade project, providing detailed calculation of load at risk, timing and options (alternatives) analysis (see Appendix 8.10).

Tullamarine new zone substation

Nuttall asserts that 'there is not a clear demonstration that energy at risk is sufficient to justify the timing of the project.'[193]

In response to Nuttall's criticism, JEN has developed a business case for the new Tullamarine Zone Substation project, providing detailed calculation of energy at risk, timing and option analysis (see Appendix 8.11).

Craigieburn new zone substation

Nuttall asserts that:

> 'The cost of energy at risk does not justify the project, and other lower cost options have not been considered. The AER's revised maximum demand forecast at the Somerton Zone Substation further support project deferral.'[194]

Through the development of a more detailed strategic planning paper, JEN agrees with Nuttall's comment that the commissioning of the project can be deferred into the 2016-20 regulatory control period based on energy at risk calculation. However, JEN believes that land acquisition should still proceed in 2011-15 due to the scarcity of land in the rapidly developing area.

JEN also notes Nuttall's comment that 'Jemena's cost for this project is on the high side of a reasonable range. We have estimated this project cost to be around $10 million'. JEN has requested further information about this assertion in a letter to the AER on 29 June 10. JEN has received advice from the AER on 16 July 2010 and will make a detailed response as soon as practicable.

TTS-CN-CS-TTS 66kV loop upgrade

Nuttall asserts that 'the cost of energy at risk appears to justify project and the alternative options have been reasonably considered.'[195]

While JEN accepts the AER/Nuttall position on this project, JEN does not understand why a probability of 90 per cent (not 100 per cent) is given for a project that is considered justified for proceeding in the regulatory control period. JEN would appreciate an explanation from the AER as to Nuttall's logic in this regard.

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[193] Ibid.

[194] Ibid.

[195] Ibid.

KTS-MAT-AW-PV-KTS 66kV loop upgrade

Nuttall asserts that 'the cost of energy at risk indicates the project should be deferred by 1 to 2 years.'[196]

In response to Nuttall's criticism, JEN has developed a business case for the KTS-MAT-AW-PV-KTS 66kV loop upgrade, providing detailed calculation of load at risk, timing and options analysis (see Appendix 8.12).

Strategic planning papers

JEN has completed the following strategic planning papers since its November 2009 regulatory proposal:

- Somerton zone substation supply area (see Appendix 8.13)
- Flemmington zone substation supply area (see Appendix 8.14)
- Coolaroo zone substation supply area (see Appendix 8.15)
- Broadmeadows zone substation supply area (see Appendix 8.16).

Distribution Substation Augmentation (DSA) project

Nuttall asserts that:

> 'it is unclear how effective the transformer replacement program will be in reducing failure rates. A low probability has been applied to allow for existing levels of upgrades, with some allowance for escalation of volumes.'[197]

The DSA program represents a major initiative of JEN to maintain asset integrity and supply reliability in the face of increasing substation overloading. In response to the AER's rejection of this program, JEN notes:

- the program is not intended to increase supply reliability or quality, but rather to arrest the expected decline over the forthcoming regulatory control period due to increasing overload-related failures. Apart from causing transformer failures, overload is likely to result in increasing localised customer outages as well as customers receiving supply voltages lower than the Electricity Distribution Code limits
- JEN rejects Nuttall's argument that heavily utilised transformers cannot be identified with sufficient accuracy to approve this program. The list of substations included in the program is outputted from JEN's Substation

[196] Draft decision, Table 8.22, p. 325.

[197] Ibid.

Utilisation Profiling System (SUPS) which uses customer energy consumption to compute maximum demand on the distribution transformers. A sample of overloaded substations is tested on site to confirm the accuracy of the model prediction

- the AER has argued that the January 2009 heatwave will have caused all at-risk substations to have failed, and therefore a pre-failure augmentation program would be unnecessary. This is incorrect as it does not account for the most common failure mechanism which is accelerated degradation of paper insulation under overloaded condition. Overloaded substations that survive January 2009 heat wave are more likely to fail during the next heat wave, with the resultant health and safety hazards that accompany the failure.

Notwithstanding the above, JEN has taken on board the AER's comments and has extended the transformer augmentation program from the current 6-year to 7-year, effectively reducing the program expenditure by about 17 per cent in 2011-2015 (see Appendix 8.17 for the supporting strategic planning paper).

Other Nuttall/AER comments

- Nuttall criticises JEN's use of a load profile based on 1999-2000 summer – JEN notes Nuttall's comments and has adopted the load profile of 2007-2008 summer in all its business cases and strategic planning papers. JEN considers that 2007-2008 reasonably reflects a 50 POE summer which forms the basis of JEN's planning methodology.

- Nuttall's probability assessment has taken into account that JEN has over-forecasted its maximum demand forecast as determined by ACIL Tasman. As stated in chapter 5 JEN has reconciled its bottom-up forecast with the revised forecast provided by NIEIR, and in the process has confirmed that the zone substation maximum demand forecast, as submitted in November 2009, remains appropriate for the revised proposal.

- The AER has transferred JEN's property purchase for zone substations from "non network – other" into "reinforcement" category. JEN believes that it is appropriate to include zone substation property purchase in "non network – others" category because while 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 due to scarcity of suitable land parcels. For this reason JEN has retained zone substation property purchase in "non network – others" capex category.

Further project optimisation

Since JEN's original regulatory proposal, JEN has conducted another review of its forecast capex, in line with what was revealed through the development of supporting documentation. In addition to the reinforcement projects noted above, the review has resulted in deferral of Alphington Zone substation project from 2012 into 2015 (part) and the subsequent regulatory control period (in part). The deferral is as a result of latest information on customer load development on the Australian Paper Mill (APM) site, as the timing of the new zone substation development is determined by customer load requirement.

8.6 Reliability and quality maintained (RQM)

8.6.1 Summary of AER's draft determination and decision

In its draft decision, the AER states that it has assumed the current level of RQM expenditure to represent an efficient base to maintain reliability and quality of supply.[198]

The AER reviewed the majority of the asset categories reviewed by Nuttall and in all cases rejected JEN's proposed expenditure for these asset categories. In all cases, the AER agreed with Nuttall's findings about: (a) the need for or reasonableness of proposed programs (including management of risks); or (b) JEN's failure to demonstrate that its models' assumptions were fit for purpose.

The AER's review covered the following RQM asset categories:

- pole top structures
- zone substation
- pole replacement
- conductor replacement
- distributor switchgear
- underground cables
- reliability.

The AER agreed with Nuttall's recommendations in each case that allowances should be based on historical trend with some allowance for ageing of the network.

198 Draft decision, p. 339.

Adjustments made by the AER to all of JEN's asset categories are stated to have been made by "subtracting the DNSP's forecast against the AER's repex model forecast".[199] In other words, all AER adjustments to RQM expenditure have been made as per Nuttall's repex model findings.[200]

8.6.2 JEN's response to the AER's draft decision on approach

The AER and Nuttall have treated historical replacement levels of expenditure as being prudent and efficient. It appears that the AER and Nuttall assume, on this basis, that any significant increases in forecast capex above historical levels are based on an unreliable forecasting method.

In particular, JEN notes that Nuttall's main criticism that the DNSPs' 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".[201] However, this approach ignores the future needs of JEN's business.

The AER's review effectively adopts Nuttall's analysis and forecasting methods. It provided a formulaic response to each category of proposed expenditure. JEN believes that the approach adopted by the AER and Nuttall of automatically concluding that a significant increase in forecast expenditure cannot be representative of a prudent and efficient operator does not meet the requirements of clause 6.5.7of the Rules. Consideration of historical expenditure is just one of 10 capex factors that the AER must consider is deciding whether JEN has meet the capital expenditure criteria set out in clause 6.5.7(c) of the Rules.

As commented in relation to the AER's approach to reinforcement above, this approach arguably does not have adequate regard to the forward-looking nature of the capital expenditure objectives and capital expenditure criteria.

Again JEN notes that this approach does not appear to be consistent with the clause 6.12.3(f) of the Rules, in that the substitute amount or value is not determined on the basis of JEN's regulatory proposal or amended from its regulatory proposal only to the extent necessary to enable its approval in accordance with the Rules.[202] JEN requests that the AER consider this when making its final determination.

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[199] AER, op. cit. p. 343.

[200] AER, op. cit. p. 338.

[201] Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 65.

[202] Clause 6.12.3(f) provides that the AER can only substitute an amount for that proposed by the DNSP if this amount is determined on the basis of the DNSP's regulatory proposal, and amended

8.6.3 JEN's response to the AER's draft decision on technical matters

Documents prepared since November 2009

In support of its RQM program, JEN has completed the following documents:

- Zone Substation YTS (Yarraville) business case - Replace 66kV Switchgear and Retire HV Switchyard (see Appendix 8.18)
- strategic planning papers:
  - pole top structure replacement (see Appendix 8.19)
  - pole replacement and reinforcement (see Appendix 8.20)
  - underground cable replacement (see Appendix 8.21)
  - overhead conductor replacement (see Appendix 8.22)
  - High voltage installation replacement program (see Appendix 8.23)
  - zone substation transformer replacement (see Appendix 8.24)
  - zone substation circuit breaker replacement (see Appendix 8.25)
  - pole top fire mitigation (see Appendix 8.26)
  - automatic circuit reclosers and remote control gas switches (see Appendix 8.27)
  - reactive fault mitigation (see Appendix 8.28)
  - superceded supervisory cable retirement plan (see Appendix 8.29)
- other:
  - forecast asset replacement volumes prepared by PB (see Appendix 8.2).

The strategic planning papers noted above provide the context for each program of replacement, including the needs that will be addressed by each. JEN considers each program of replacement and the associated expenditure to be necessary in

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from this basis only to the extent necessary to enable it to be approved in accordance with the NER.

order to achieve an outcome that is consistent with the National Electricity Objective (**NEO**), which is to:

> ‘promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –
>
> (a) price, quality, safety, reliability and security of supply of electricity and
>
> (b) the reliability, safety and security of the national electricity system.’

The AER’s draft decision currently fails to make sufficient allowance for JEN to fully undertake its proposed replacement programs in the forthcoming regulatory control period. Section 7A(2) of the NEL provides that:

> ‘a regulated network services provider should be provided with a reasonable opportunity to recover at least the efficient costs incurred by an operator in:
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.’

Should the AER’s draft decision not be amended to allow for the full scope of JEN’s proposed asset replacement strategy, JEN will not be given a reasonable opportunity to recover its efficient costs as required by section 7A(2) of the NEL.

PB expert report

As mentioned above, Nuttall relied heavily on a repex model developed for the AER in forming its opinion of JEN’s RQM forecasts.[203]

JEN engaged PB to provide an independent report[204] on the asset replacement volumes that had been submitted to the AER as part of JEN’s regulatory submission. The review includes:

- an analysis of the asset replacement volumes for categories where significant increases in replacement volumes are forecast over 2011-2015
- an examination of the approach used by Nuttall in its assessment of the capex requirements of Victorian distribution businesses undertaken for the AER. While Nuttall adopted age-based modelling to forecast all asset replacement volumes, JEN has used aged-based modelling developed by

[203] Draft decision, p. 339, and Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, section 3.

[204] PB, *JEN Forecast Asset Replacement Volumes*, July 2010.

PB to forecast asset replacement volumes in some asset classes. This report includes an analysis of each of the modelling approaches.

PB made the following conclusions from its review:

Nuttall approach

PB has the following concerns with Nuttall's approach adopted to assess expenditure proposals and to recommend capex allowances:

- distribution business' models have been found to be suitable for business asset management practices but inappropriate for the regulatory review process
- there is little fundamental analysis of the business' needs, risks, and proposed expenditure (prudency and efficiency) to support the dismissal of the business' AMP's
- it relies on comparison 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 next regulatory control period
- considerable discretion has been exercised with regard to selection of a substitute forecast which does not appear to align with the National Electricity Rules
- the application of the repex model as the basis for accepting/rejecting the replacement capex proposals, on an activity code (asset) level, creates an inherent bias in the total substitute forecast. Nuttall rejects all activity code forecasts above the repex model forecast (or historical level) but accepts activity code forecasts which are below, resulting in a substitute total replacement forecast that is materially below both the forecasts proposed by the businesses, and the total replacement forecast predicted by the calibrated repex model.

The repex model

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. PB's review of the repex model highlights the following concerns:

- use of a normal distribution as the basis for modelling remaining life, rather than the Weibull distribution widely acknowledged in reliability engineering literature
- the assumed standard deviation has not been demonstrated to fit equipment failure profile
- 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.

JEN's forecast asset replacement volumes

PB has reviewed the use by JEN of the PB Model to produce forecasts of certain asset replacement volumes. This includes a review of the inputs and outputs of the model and a comparison of the way in which the PB Model has been used to produce asset replacement volumes forecasts in the current and previous regulatory submissions. PB concludes that:

- 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."[205]

- 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.

Other Nuttall/AER comments

- *Zone substation transformer replacement* – The AER and Nuttall assert that JEN's life cycle management plan stated that the notional replacement dates for transformers (according to conditions) should occur sometime after the forthcoming regulatory control period.[206] JEN believes the AER and Nuttall have misinterpreted the information provided in JEN's transformer life cycle management plan.

  Section 6.11 of the transformer life cycle management plan states that "there are 34 transformers between 41 and 55 years old, plus 6 transformers over 80 years old. To manage the high cost of transformer replacement from an ageing population, and considering the long lead times for procurement, and limited spares, this current life cycle plan sets out a notional list of transformers for replacement." It goes on to say that "Appendix B sets out the notional replacement plans for the entire transformer population. The decision to proceed with each of these planned activities will be made based on a transformer condition assessment at a time prior to the scheduled date. This assessment would include an assessment of DP, transformer moisture content and mathematical modelling of the end of life." The notional replacement dates are therefore not based on transformer conditions but rather on age to allow long-term plans to be made. Prior to decision taken to replace transformers, transformer condition assessment will be carried out.

205 Draft decision, p. 368.

206 AER, op. cit. p. 370.

The transformers targeted for replacement in 2011-15 have been assessed based on JEN's transformer model and recent condition test results. Details of JEN's assessment is provided in the strategic planning paper "Zone Substation Transformer Replacement" (Appendix 8.24).

- *Zone substation circuit breakers and switchgear replacement* – The AER and Nuttall express the concern about the weightings that were applied to various factors to determine the resulting prioritisation, and was not satisfied JEN's pro-active switchgear replacement program was reasonable. In response to these comments, JEN's strategic planning paper "Zone Substation Circuit Breaker Replacement" (Appendix 8.25) provides further details about the drivers and options considered for the proposed replacement program. JEN's planned circuit breaker replacement program is in line with historic trend, with the increase mainly attributed to alignment with other major zone substation programs e.g. ES switchgear replacement is carried out when the 3rd transformer and 3rd 11kV bus are added to the station due to reinforcement driver.

- *Conductor replacement* – The AER and Nuttall express the concern that the PB replacement model used to forecast the replacement volume is not calibrated, that there is limited success in accurately focusing replacement needs using the same model since 2000, and in practice more detailed review and testing of assets will occur prior to any replacements being approved.[207] JEN notes that PB has assessed JEN's use of the replacement model, including model inputs, and has concluded that the approach appears sound. Moreover, the model forecast is supported by the recent inspections of HV steel conductor which indicates that approximately 110 km of this conductor will need to be replaced over the 2011 to 2015 period (which is consistent with the PB model forecasts). JEN has approximately 400km of steel HV conductor almost all of which is located in the HBRA part of the network therefore risk of bushfire ignition, as a result of conductor failure, is very real. JEN notes that in its draft decision the AER has allowed significant steel conductor replacement expenditure for SP AusNet based on the 2009 bushfires experience in Victoria. For details refer to strategic planning paper "Overhead Conductor Replacement Program" (Appendix 8.22).

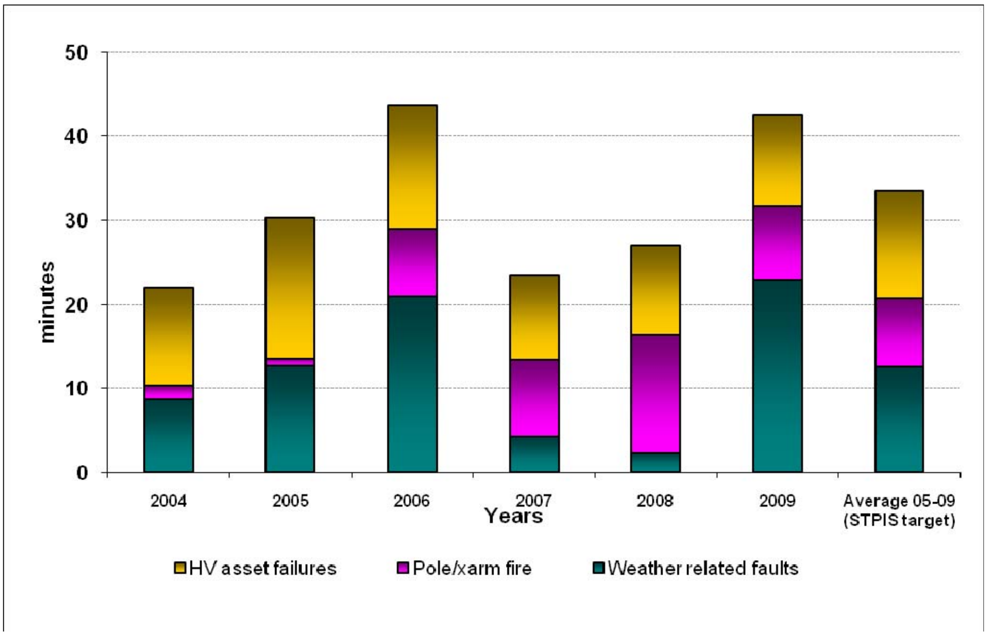
- *Reliability* – The AER and Nuttall assert that detailed justification for the projects in this category is not clear and that the matters affecting reliability in the current regulatory control period are largely similar to those in the forthcoming regulatory control period. JEN is concerned that the AER has not accepted climate change impacts, particularly more violent and frequent wind and lightning storms. JEN notes that the AER has not denied that

[207] Draft decision, p. 373.

climate change will impact businesses in the forthcoming regulatory period, rather the AER has noted that the impact will be gradual and is to a large extent reflected in the 2009 base year. JEN reiterates that the AECOM report clearly shows the likely impact of climate change on JEN's network in the forthcoming period. Whilst JEN has accepted that climate change is reflected in its 2009 base year opex and that climate change will have a gradual impact on opex, JEN 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.

Analysis of outage causes from 2004 to 2009 has revealed that "weather related faults", "pole/crossarm fires" and "high voltage asset failures" contributed to significant variability of the annual reliability performance. Figure 8-2 shows the SAIDI impact of the three outage cause from 2004 to 2009:

Figure 8-2: SAIDI impact of outage causes

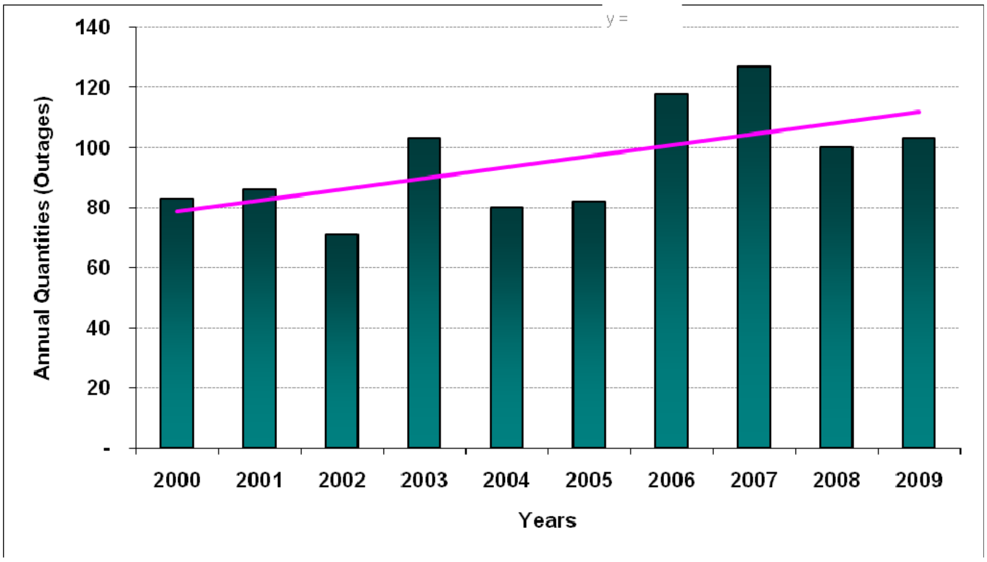


JEN has also shown in the graph average SAIDI impact (2005 to 2009) from the 3 causes based on the principle adopted for STPIS target setting. It can be seen that STPIS targets, based on average performance, will be challenging to meet if violent weather events become more frequent such as what have been experienced in 2006 and 2009 as is predicted by AECOM's modelling. AECOM predicts that 2009 is representative of the weather conditions that will be experienced by JEN in the forthcoming regulatory period. It is clear from the graph above, that if 2011-2015 weather related faults are in line with such faults in 2009, JEN's SAIDI performance will deteriorate significantly beyond the 2005 to 2009 average target set under the STPIS, unless JEN undertakes additional expenditure to offset the increasingly challenging weather conditions.

What is not apparent from the above graph is the rising trend of asset failures. The trend in the numbers of high voltage equipment failures is increasing at the rate of 3.7% per annum, as shown in Figure 8-3. Whilst this increase is apparent in the numbers of failures, it is not yet apparent in SAIDI as presented earlier. There is no obvious increasing trend of SAIDI relating to asset failure with the average contribution to the JEN SAIDI being 13 minutes per annum over 2005-9 regulatory control period.

The discrepancy between the observed increases in asset failure volumes without a corresponding increase in SAIDI can only be attributed to one reason. Over recent years, JEN has predominantly been addressing the symptoms of asset failure rather than the underlying causes with the installation of recloser equipment and remote controlled switchgear to increase switching flexibility, reducing the numbers of customers affected and the duration of the outages for asset related failure.

Figure 8-3: High voltage equipment failures resulting in feeder & ACR outages



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 is therefore proposing a step-up in asset replacement expenditure to arrest the increasing trend of asset failure as assets reach their end of life. JEN is also proposing to provide a modest increase in its reliability maintained expenditure involving the following programs/projects (in addition to projects/expenditure in the current regulatory control period):

- 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.

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.

Further project optimisation

Since JEN's original regulatory proposal, JEN has conducted another review of its forecast capex, in line with what was revealed through the development of supporting documentation. Specifically for RQM projects, the review has resulted in:

- removal of the overlap between pole top replacement forecast and pole fire mitigation program
- removal of the overlap between pole replacement forecast and the undersized pole rectification program
- deferral of the replacement of FF zone transformers due to latest transformer test results (obtained after the November 2009 submission) which indicate that there is sufficient remaining life to last into the next regulatory control period.

8.7 Environmental, safety and legal

8.7.1 Summary of AER's draft determination and decision

The AER approached its assessment of environmental, safety and legal forecast capex on the basis that the historical underlying trend in capex represented a starting point for assessing the reasonableness of JEN's forecast capex.[208]

The AER noted that the DNSPs' forecast capex proposals focussed on:

- compliance with the Victorian Environmental Protection Authority environment protection policies
- safety obligations under the Electricity Safety Act 1998 (Vic) and associated regulations.

The AER considered DNSPs' indicative project lists and in particular whether they were linked to larger documented strategies/programs of work including an economic assessment of the need for the overall work program and the scale and timing of the proposed works.[209]

JEN provided risk assessment spreadsheets in support of its proposed projects. Whilst the AER considered that these confirmed the need to undertake work, it noted that there was no associated economic analysis assessing the project scope, cost-benefit and timing of each project.

The AER considered that the amounts proposed by JEN suggested a step change in its obligations entering the new regulatory control period. However, the ESV advised that regulatory obligations of the Victorian DNSPs had not altered as a result of the amendments to the Electricity Safety Act 1998 and associated regulations. Accordingly, the AER concluded that the DNSPs had not demonstrated a material step change to their compliance with environmental legislation and regulations or Victorian safety legislation and regulations.

Accordingly, the AER considered that none of the DNSPs' proposed increases in capital expenditure (an increase of 12 per cent for JEN) had been justified.

The AER substituted all DNSPs' proposed amounts based on a continuation of the historical expenditure trend.

[208] Draft decision, p. 399.

[209] AER, op. cit. p. 401.

8.7.2 JEN's response to the AER's draft decision on approach

JEN notes that the AER's reasoning for its draft decision to substitute JEN's proposed forecast spend based on a continuation of the historical expenditure trend is as follows:

- historical underlying trend in capex represents a starting point for assessing the reasonableness of a DNSP's (entire) capex proposal[210]
- the DNSPs currently comply with their obligations
- a significant increase in capex can only be justified by identified step changes in regulatory obligations or requirements that will materially affect a DNSP's capex requirement; there have been no such changes
- the DNSPs have not demonstrated material step changes to their compliance obligations and therefore the proposed increases are not justified, and accordingly
- all proposed amounts should be substituted for an amount representing a continuation of the historical expenditure trend.

The AER acknowledges in its draft decision that JEN's risk assessment materials confirm the need to undertake work in this category. However, the AER's main stated concern is that JEN has not undertaken any economic analysis assessing each project's scope, cost-benefit, or timing.

Again, this approach arguably does not have adequate regard to the forward-looking nature of the capital expenditure objectives and capital expenditure criteria. JEN notes that this approach does not appear to be consistent with the clause 6.12.3(f) of the Rules, in that the substitute amount or value is not determined on the basis of JEN's regulatory proposal or amended from its regulatory proposal only to the extent necessary to enable its approval in accordance with the Rules.[211] JEN requests that the AER consider this when making its final determination.

Electricity Safety Management Scheme (ESMS)

JEN does not agree with the ESV's advice 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.

[210] Draft decision, p. 399.

[211] Clause 6.12.3(f) provides that the AER can only substitute an amount for that proposed by the DNSP if this amount is determined on the basis of the DNSP's regulatory proposal, and amended from this basis only to the extent necessary to enable it to be approved in accordance with the NER.

JEN notes that the general duty in section 98 of the ESA requires JEN to "minimise as far as practicable" the hazards and risks to the safety of any person, and of damage to the property of any person, arising from the supply network. Contrary to the suggestion of the AER[212] JEN does not consider this to be a similar duty to that in section 75 of the previous version of ESV, which only required that JEN take "reasonable care" that all parts of its network were designed, constructed, operated and maintained in accordance with the regulations, and were safe and operated safely. Rather, JEN considers the duty to "minimise as far as practicable" to be a higher standard than the requirement to take "reasonable care."

JEN's proposed ESMS expenditure is based on evaluation of risk into three categories (intolerable, As Low As Reasonably Practicable (**ALARP**) and tolerable) and mitigation of those risks.[213] This differs from the risk management process set out in JEN's previous voluntary (and currently applicable) ESMS.[214]

JEN notes that its existing voluntary ESMS provides that "any network element may require safety assessment to ensure that risks are able to be systematically identified and quantified so that control measures are able to be implemented to keep the risk at as low a level as reasonably practicable".[215] However, this is a voluntarily assumed responsibility in relation to taking "reasonable care" (under section 75 of the previous version of the ESA). In contrast, the obligation to "minimise as far as practicable" hazards, risks and damage to property (under section 98 of the current ESA) is mandatory.

The formal safety assessments (**FSA**) conducted by JEN contain risk controls which require additional capex and opex. The additional opex is detailed in Appendix 7.2. The majority of the capex is included under the environmental, safety & legal category.

Non-compliance to Existing Codes / Legislation

AER's use of historical trend is based on the assumption that JEN is compliant with legislation. JEN's proposed investment in power quality and reactive compensation at points of connection are projects to address current non-compliance which JEN will become aware of due to greater knowledge.

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[212] AER, Letter to ESV, *Electricity Safety Act and associated regulations*, 25 March 2010, p. 2.

[213] Proposed JEN ESMS, provided to ESV on 20 April 2010, see p. 32 (section 3.1.5.1).

[214] JEN's existing ESMS, particularly part 30-2610 (Risk Management), part 30-2650 (Risk Management (Methodology)) and part 30-2651 (Risk Assessment (Application)).

[215] See JEN's existing ESMS, part 30-2610 (Risk Management), p. 1.

8.7.3 JEN’s response to the AER’s draft decision on technical matters

Documents prepared since November 2009

In support of its Environmental, Safety and Legal program, JEN has completed the following strategic planning papers:

- public lighting switch wire removal (Appendix 8.30)
- ground fault neutralisers installation and SWER removal (Appendix 8.31)
- power quality (Appendix 8.32)
- reactive compensation at point of connections (Appendix 8.33)
- vegetation management - cost impact of electric line clearance regulations (Appendix 8.34)
- neutral screened services (Appendix 8.35)
- trial of neutral conditions monitor (Appendix 8.36).

These documents provide additional support to the projects and programs including where applicable analysis of scope, cost-benefit and timing.

Regulation changes

Regulation changes or updates that have occurred since November 2009 include:

- Electricity Safety Line Clearance Regulations 2010
- Energy and Resources Legislation Amendment Bill 2010.

The implications of these regulation changes are:

- a new capex requirement for undergrounding or the use of aerial bundled cables (**ABC**) arising from the Electricity Safety Line Clearance Regulations 2010
- an additional general objective, to minimise 'as far as practicable' the bushfire danger arising from an 'at-risk supply network' arising from the Energy and Resources Legislation Amendment Bill 2010. While this has not increased JEN’s proposed capex on bushfire mitigation, it reinforces the need for such programs.

A joint meeting was held at 3.30pm on 14 July 2010 at the ESV's offices and attended by staff from the AER, the ESV and the five distributors. JEN considers that at that meeting both the ESV and the AER agreed that:

- in the forthcoming regulatory period distributors face material increases in the scope and volume of work required to meet their safety obligations, and
- the extent of the increase in scope and volume of work for each distributor will be assessed by the ESV in a timeframe that allows the AER to consider the ESV's assessment and incorporate it into the AER's final determination.

JEN requests that the AER provide it with an opportunity to revise its costs once the extent of the increase in scope and volume of work has been agreed (expected by mid August 2010).

8.8 SCADA and network control

The AER noted that JEN's proposed project was part of a larger continuing program consistent with JEN's strategy to improve security at zone substation, and that Nuttall had considered this to be prudent and efficient.[216]

The AER accepted JEN's proposed forecast capex for SCADA and network control.

8.9 Non-network IT

8.9.1 Summary of AER's draft determination and decision

The AER approached its assessment on the basis that the historical underlying trend in capex (data from 2004-2008) represented a starting point for assessing the reasonableness of each DNSP's capex proposal,[217] and in particular, that the actual/out-turn expenditure represented the efficient capex amount.[218]

The AER agreed with Nuttall's assessment that the DNSPs did not have agile IT architecture, and that this would hinder the DNSPs' ability to complete the IT projects proposed. The AER considered that DNSPs were likely to defer projects or adopt alternative projects in the forthcoming regulatory control period.

The AER adopted Nuttall's recommended expenditure for JEN i.e. deferring JEN's proposed expenditure 2014 and 2015 and spreading 2011-2013 evenly across 2011-2015.

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216 Draft decision, p. 407.

217 AER, op. cit. p. 418.

218 AER, op. cit. p. 420.

8.9.2 JEN's response to the AER's draft decision on technical matters

In arriving at its substitute expenditure amounts, the AER has principally relied on Nuttall's conclusion that JEN's IT architecture is not sufficiently agile. This conclusion appears to be based on the observation that JEN has historically underspent relative to its own forecasts (JEN underspent during 2004-2008 from a proposed $55 million to an actual audited spend of $41 million).[219]

The AER's reasoning process can essentially be summarised as follows:

- an efficient DNSP would recognise and possess an agile IT architecture
- JEN's previous underspend (of 25 per cent of its forecast) indicated that its architecture was not sufficiently agile
- as this had not been recognised in JEN's proposal, it was safe to assume that a similar underspend would occur in the next regulatory control period.

Accordingly, the AER concluded that JEN's proposed expenditure for 2011-2013 represented the projects that were likely to be completed during the forthcoming regulatory control period.

Delivery

JEN does not agree with the AER's determination or Nuttall's opinion that JEN is not capable of delivering its proposed IT capex program for 2011-2015 and that its IT architecture is not sufficiently agile. In particular, JEN notes that:

- The IT program over 2006–2010 is expected to be in excess of $61.4 million (with $52 million incurred over January 2006 to May 2010). In parallel JEN has delivered the separate and much larger advanced metering initiative IT program.
- Any deferral of spend over 2006-2010 has been driven by external events, vendors' product replacement and not due to capability or IT architecture. Those necessary deferrals are not large in cost or scale and have been replaced by much larger programs.
- The IT program is not ambitious or large to the Jemena Group total IT program.

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219 Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 80, which states: 'Given that historical capital spend has not matched the DNSP forecasts, we believe that all the DNSPs have IT infrastructure that are too static and not sufficiently agile. Whilst the individual projects proposed by the DNSPs may be justified as being prudent and efficient, the historical inability to deliver them indicates that the projects are hampered by the lack of flexibility of the underlying IT infrastructure.'

- The program applies justified proven applications and technologies currently in place in Australian energy companies. Each major project is for a separate part of the business and IT operations with one enterprise project only consciously planned and with sequential timing to have a manageable change and disruption impact on the business.

- The AER's draft decision considered the record of IT Delivery from 2004-2008 as indicative of IT capex and delivery trends for JEN. This period was a time of great disruption as the distribution network went through two changes of ownership. This meant from the beginning of 2006 to the end of 2008 few IT assets were capitalised to become part of the regulated asset base. On acquisition in October 2006 large scale activity was ramped up in IT to catch up and modernise. Those projects were completed and capitalised from 2009 onwards.

- JEN's service provider, EB Services achieves flexibility to scale up through partnerships and preferred supplier agreements, and tendering out of major projects to the leading consulting and IT delivery firms.

Appendix 8.9 sets out the completed and work in progress program in detail.

Agility of IT architecture

JEN has undertaken an extensive IT modernisation program, and continues to do so, investing well above the allowance that has progressively improved the agility of the IT architecture. JEN's IT infrastructure plan submitted to the AER and Nuttall in February 2010 demonstrates that the IT architecture development underway is consistent with the profile described by Nuttall.

The IT architectures and technologies in place reflect the marketplace software for the energy industry, hardware infrastructure tools and techniques available at the time of investment. The technologies were mainstream and typical for the Australian energy industry at the time they were implemented.

The length of time that technologies have been utilised has been determined by business case. Typically JEN has used software applications for long periods due to their operational and financial effectiveness to the benefit of energy market participants. Over time these ageing software products inhibit the flexibility and agility of the IT systems and architecture as the regulatory rules, market requirements and the business changes.

Replacement and new investments have also been determined by new energy specific applications and technologies. After the acquisition of AGLE, the entire IT Infrastructure assets were replaced. Those assets were not part of the acquisition agreement. Therefore the opportunity was taken to modernise all hardware technologies. The IT Infrastructure is currently less than 2 years old with a forecast life of 4-5 years before the total costs of ownership is exceeded by replacement technologies. The IT Infrastructure was implemented as value for money based on competitive tender and the use of contemporary technologies.

JEN has invested both in the current period and historically in new and agile technologies. The progressive investments and IT Infrastructure Plan are consistent with the profile provided by Nuttall. JEN notes its following technical efficiencies:

- JEN's production systems are more than 65 per cent virtualised as a necessary component of being an agile environment. Systems not virtualised are due to the supplier being unable to provide virtualisation without replacement. More than 95 per cent of JEN's new market supplied software is virtualised and all in-house developed software in progress is for virtualised systems.
- JEN is progressively transitioning to tiering that is being implemented as part of the exit and transition from the current third party owned and ageing data centres.
- JEN makes extensive use of middleware and will introduce more process ware tools and connectors with the SAP replacement moving to SAP ECC6. These techniques limit the level of point to point systems necessary to just a few software applications that are unique to the energy industry and regulation.
- JEN has upgraded the underlying technologies for the customer service, billing and metering applications.
- The AMI program has implemented agile and efficient technology and architectures.

8.10 Non-network other

8.10.1 Summary of AER's draft determination and decision

The AER considered that the proposed expenditure for procurement of land associated with zone substation development should be considered under the reinforcement expenditure category.[220]

In relation to the Broadmeadows/Sunshine depot relocation/merger project, the AER considered that capex would be incurred for relocation of the Sunshine depot

[220] Draft decision, p. 431.

but not the Broadmeadows depot. However, as JEN's draft business case did not separately identify the costs associated with relocating the Sunshine depot alone, the AER substituted zero capex in place of the total amount for the proposed project.[221]

The AER approached its assessment on the basis that the historical underlying trend in capex (data from 2004-2008) represented a starting point for assessing the reasonableness of each DNSP's capex proposal, and in particular, that the actual/out-turn expenditure represented the efficient capex amount.[222]

JEN has been unable to determine the basis as to how the AER formulated its substitute expenditure amounts for JEN.

8.10.2 JEN's response to the AER's draft decision on approach

Whilst it is clear that the AER has not approved any of JEN's proposed expenditure under JEN's land and property category, it is unclear what approach the AER has adopted in arriving at its final expenditure amounts (which presumably relate only to JEN's vehicles and tools and test equipment expenditure categories, when Broadmeadows re-development and zone substation land purchase are excluded).

8.10.3 JEN's response to the AER's draft decision on technical matters

Land

As mentioned in section 8.5.3, JEN believes that it is appropriate to include zone substation property purchase in "non network – others" category because while 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 due to scarcity of suitable land parcels.

Justification for the zone substation land purchase is provided by business cases and strategic planning papers which JEN has developed:

- Tullamarine zone substation land purchase – business case (Appendix 8.11)
- Broadmeadows South zone substation land purchase – strategic planning paper (Appendix 8.16)
- Craigieburn zone substation land purchase – see Somerton zone substation strategic planning paper (Appendix 8.12)

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221 AER, op. cit. p. 431.

222 AER, op. cit. pp. 428-30.

- Alphington zone substation land purchase – Distribution System Planning Report 2009
- Bulla zone substation land purchase – Distribution System Planning Report 2009.

Broadmeadows depot

JEN has completed further reviews for the Broadmeadows depot project since its original regulatory proposal, with assistance from expert building consultants (see Appendices 8.37 and 8.38). The following four options have been considered:

- do as little as possible, stay at existing Broadmeadows site and refurbish the existing facilities to legislative standard, with staff remaining on site
- upgrade Broadmeadows site to meet full legislative and safety code obligations and relocate staff for the two year rebuild timetable
- relocate the JEN Operations to an alternative brownfield site that meets the business requirements
- relocate the JEN Operations to a new greenfield site with appropriate transport access to the Metropolitan Ring road.

The do as little as possible option is not acceptable as there are serious problems associated with safety, asbestos, oil containment and access risks. Expert advisors, Woodhead has informed JEN that the Broadmeadows depot fails to meet with a range of legislation and codes.

Woodhead advises that “The Occupational Health and Safety Act 2004 clarifies and brings Victoria’s safety laws up-to-date to reflect modern workplaces and arrangements. The Act states that people who have management or control of a workplace must take every reasonable action, and work proactively to ensure health and safety in the workplace.”[223]

There are significant penalties to management for non compliance. JEN must ensure the workplace is safe and without risks to health, and must eliminate risks to health so far as is reasonably practicable. The major safety non-compliances are substantial amount of asbestos in the warehouse and lesser amounts in all buildings as well as polluted ground surface which should be removed and / or remediated. Woodhead also advises that in order to make the Broadmeadows workplace safe the asbestos problem at Broadmeadows must be addressed:

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[223] Woodhead et al, *JEN Feasibility Study*, July 2010, section 2.1.1.

> Extremely dire consequences are possible as the release of asbestos fibres into the workplace would necessitate immediate evacuation of all personnel until the cleanup is complete and a certified safe.[224]

The buildings do not comply with major sections of the Building Code of Australia. There are also major non-compliances with the recent amendments to the Disability Discrimination Act 1992 (**DDA**), which came into effect on 5 August 2009.

Woodhead has reviewed a range of options and recommend that the lowest cost, technically suitable option for JEN is to abandon the site and to build a new depot in an adjacent location. This cost has been included in JEN's revised forecast capex.

8.11 Revised labour escalators

8.11.1 Summary of JEN's original regulatory proposal

To better reflect trends in labour market conditions leading to real increases in wages and salaries, BIS Shrapnel (**BISS**) was commissioned jointly by the Victorian distributors to produce a set of escalators for the forthcoming regulatory control period (see Appendix 7.2 of JEN's original regulatory proposal). JEN applied these escalators in producing its capex and opex forecasts. JEN notes that while it correctly applied the nominal escalators in the BISS report, the real escalators shown in its original regulatory proposal (and used in JEN's forecast data model) differ from those of BIS Shrapnel because of different inflation forecasts.

8.11.2 Summary of AER's draft determination and decision

In its draft decision, the AER did not accept JEN's proposed labour escalators and substituted its own escalators as follows:

224 Woodhead et al, *JEN Feasibility Study*, July 2010, section 2.1.1.

Table 8-4: AER draft decision JEN labour cost escalators (per cent)

Escalator	2010	2011	2012	2013	2014	2015
Internal labour						
JEN proposed	3.84	2.43	2.63	2.73	2.63	2.43
AER	1.63	0.98	0.99	0.88	1.94	1.46
External labour						
JEN proposed	3.04	1.93	2.63	3.03	2.53	2.33
AER	0.65	0.87	1.48	1.89	1.87	0.69

AER reasons for not accepting JEN forecasts

The AER assessed the BIS Shrapnel labour escalators in detail in Appendix K of its draft decision. In its draft decision, the AER made two general points applicable to all escalators:

- it considers that its conclusions from the recent final New South Wales (NSW), Australian Capital Territory (ACT), Queensland (QLD) and South Australian (SA) decisions are still applicable with respect to the methodology used for estimating each escalator.

- it has a preference for updating real cost escalation factors with the most up to date forecasts at the time of its final decision. This preference is consistent with the capex and opex criterion in the Rules which requires the AER to be satisfied that the capex and opex forecasts reasonably reflect a realistic expectation of demand forecast and cost inputs required to achieve the capex and opex objectives.[225]

In its draft decision the AER said that while BIS Shrapnel's forecast methodology appeared reasonable, it had concerns with BIS Shrapnel's preferred measure of changes in the price of labour, and the application of these forecasts.[226]

Although BIS Shrapnel considered that 'AWOTE EGW wages' were the appropriate escalator for internal labour costs, the AER considered that the state labour price indices (LPI) was the measure "that most reasonably reflects the labour costs that a Victorian DNSP is likely to incur."[227] The AER engaged Access Economics to develop forecast growth in EGW (utilities) and LPI wage measures.

225 Draft decision, Appendix K, s. K.1, p. 114.

226 AER, op. cit. p. 132.

227 Ibid.

The draft decision further indicated that wages forecasts should be subject to productivity adjustment (which Access Economics had incorporated but BIS Shrapnel had not):

> The AER considers that productivity adjustments can be an important factor in forecasting actual business costs and notes this approach is consistent with previous regulatory decisions. The AER further notes that Access Economics considers productivity factors as a key driver of wage differentials and has incorporated productivity into its modelling. The AER supports the application of Access Economics' productivity impacts in the modelling of its wage cost growth forecasts and does not consider it necessary to include further productivity adjustments.[228]

In an additional adjustment to wages escalation, the draft decision split internal labour into two components: specialist EGW employees and clerical and administrative labour. According to the draft decision, the latter group's wages "are more likely to reflect those of the general economy."[229] Despite advice from several DNSPs (including JEN) that their internal labour operated solely within the EGW sector, the AER derived a split of each of the Victorian DNSP's internal labour costs based on data provided within the regulatory templates.[230] The AER then developed a weighted average internal labour escalator for each DNSP.

For the outsourced labour cost escalator, the AER accepted BIS Shrapnel's methodology, which was a simple averaging of the ABS classifications of 'property' and 'property and business services' wages under ANZIC codes.[231] However, the AER considered it important to utilise the most recently available data to calculate labour cost escalators, as provided by Access Economics.

8.11.3 JEN's response to AER's draft determination and decision

The key points of difference between the Victorian DNSPs and the draft decision on labour escalators are whether:

- the appropriate measure for internal labour escalation should be AWOTE or LPI based
- productivity should be included in wage cost growth forecasts
- adjustments should be made to internal labour escalators on an assumed basis of 'pure' EGW employees and other employees

[228] AER, op. cit. p. 133.

[229] AER, op. cit. p. 134.

[230] AER, op. cit. p. 135. The draft decision notes that in-house and related party labour costs reported in the operating and maintenance expenditure templates were aggregated for each Victorian DNSP's base year.

[231] AER, op. cit. p. 136. ANZSIC is the Australian and New Zealand Standard Industrial Classification 2006.

- the AER's treatment of outsourced labour costs is appropriate
- Access Economics provides labour forecasts (on whatever basis) which are superior to those from other sources such as BIS Shrapnel and KPMG Econtech.

There is also the broader issue of the AER's stated preference for updating real cost escalation factors with the most up to date forecasts at the time of its final decision. This is considered below.

Internal labour escalation

Previous AER decisions

In its draft decision, the AER stated that it has applied the LPI measure consistently, and references a number of previous determinations including NSW.[232]

> However, the AER applied the KPMG Econtech average weekly earnings (AWE) forecasts for NSW, as is evident from the KPMG Econtech report to the AER. The AER has engaged KPMG Econtech to update the labour cost forecast for NSW, Tasmania, the ACT and Australia. These forecasts reflect the following factors:
>
> Average Weekly Earnings data obtained by special request from the Australian Bureau of Statistics (ABS). This includes historical Average Weekly Earnings data up to November 2008. [233]

In addition, in its NSW decisions, the AER acknowledged Econtech's general modelling credentials:

> The AER also notes CEG's acknowledgment of Econtech as a reputable forecaster.[234]

Relevance of AWE/AWOTE instead of LPI

Both KPMG Econtech (**Econtech**) and BIS Shrapnel support the merits of using AWE/AWOTE as a more appropriate measure for estimating actual labour costs for a business than LPI. In particular, the LPI does not capture changes in labour costs associated with retaining labour.

Econtech was commissioned by three Victorian DNSPs to assess the AER's draft decision on Victorian labour cost escalation (see Appendix 8.6).[235]

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232 AER, op. cit. p. 132.

233 KPMG Econtech, *Updated Labour Cost Growth Forecasts*, 25 March 2009, p. 4.

234 AER, *New South Wales distribution determination 2009–10 to 2013–14, Final decision*, 28 April 2009, pp. 491-2.

Econtech make the following points:

- Whilst the LPI is the most appropriate measure of *wage movements*, AWOTE is a better indicator of overall *labour cost movements*, because it captures changes in labour costs that are driven by changes in the composition of employment.[236]

- Identifying which measure is more appropriate conceptually requires a consideration of its intended use (i.e. what it is that we are trying to measure). In this case, the intended use of the labour cost measure is as an escalation factor for aggregate labour costs for the DNSPs over the regulatory period. Such labour costs are driven by both wage movements and changes in the composition of employment i.e. changes in the proportion of different occupations within a given industry sector, regional area or economy as a whole. In the current economic climate, compositional impacts within industries, as well as competition between industries, is playing an influential role in the overall labour costs faced by employers.[237]

- Historically, LPI growth has been lower on average than AWOTE growth…The trend for AWOTE growth to outpace LPI growth reflects wage pressures that are created by macroeconomic factors. By using the LPI, the AER is likely to have underestimated wage pressures associated with macroeconomic factors, meaning its labour cost escalators may underestimate the true change in labour costs faced by the DNSPs over the regulatory period.[238]

BIS Shrapnel supports this reasoning:

- Importantly, the LPI does not reflect changes in the skill levels of employees within industries or for the overall workforce, and will therefore understate (or overstate) wage inflation if the overall skill levels increase (or decrease). The labour price index is also likely to understate true wage inflationary pressures as it does not capture situations where promotions are given in order to achieve a higher salary for a given individual, often to retain them in a tight labour market.

- For this reason, BIS Shrapnel prefers using AWOTE as the measure that best reflects the increase in wage cost changes (or unit labour costs, net of

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[235] KPMG Econtech, *Assessment of the AER's Draft Decision on Labour Cost Escalation: Victoria*, 13 July 2010. This was commissioned by CitiPower, Powercor and United Energy Distr bution.

[236] KPMG Econtech, op. cit. p. vi.

[237] KPMG Econtech, op. cit. p. iii.

[238] KPMG Econtech, op. cit. pp 19-20.

> productivity increases) for business and the public sector across the economy.[239]

The AER references the ABS as stating that the LPI index is a preferable measure of changes in wage rates over AWE/AWOTE.[240] This is correct, but as Econtech have pointed out above, AWOTE is a better indicator of overall *labour cost movements.* JEN submits that the AER should address fitness of purpose when choosing a wage measure. The ABS developed the LPI index in response to the decentralisation of the labour market and more employees being covered by diverse agreements. The LPI index purposely ignores these agreements to capture the underlying wage trend and thus provides a high-level macroeconomic indicator. The LPI index was not developed for the purposes of forecasting actual labour costs for a business.

Productivity

As noted earlier, the AER considered in its draft decision that productivity adjustments can be an important factor in forecasting actual business costs and noted that this approach was consistent with previous regulatory decisions.

As with the AER's historical preference for the use of LPI, JEN notes that previous regulatory decisions have not universally incorporated productivity in real labour escalation. The final decisions for Energex and Ergon in Queensland (2010) did not raise the issue of labour productivity[241] and it appears from the Access Economics report accompanying the Queensland final decisions that Access Economics' labour escalators excluding productivity adjustment were adopted by the AER.[242] On the other hand, the AER's NSW electricity decisions did allow for labour productivity as modelled by Econtech:

> The AER notes Econtech's labour productivity assumptions are incorporated in its MM2 model through its labour productivity index. Further, MM2[243] incorporates assumptions regarding the growth in labour efficiency for each industry, enabling separate labour productivity assumptions for each 1–digit ANZSIC industry. The AER is therefore satisfied with the approach and methodology applied by Econtech to incorporate productivity in its wage growth forecasts.[244]

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239 BIS Shrapnel, *Wages outlook for the electricity distribution sector in Victoria*, Prepared by BIS Shrapnel for the Victorian Electricity Distributors, June 2010, pp. A-1 and A-2.

240 Draft decision, Appendix K, p. 132.

241 AER, Queensland distribution determination 2010–11 to 2014–15, Final decision, May 2010, Appendix F.

242 Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, Table 6.5, p. 69.

243 MM2 is the Murphy Model 2 as developed by Econtech.

244 AER, *New South Wales distribution determination 2009–10 to 2013–14,* Final decision, 28 April 2009, pp 491-492.

BIS Shrapnel do not specifically incorporate productivity adjustments into its labour cost forecasts. It cites several problems with productivity measurement, particularly the measurement of output in certain industries, including the electricity, gas and water sector. [245]

JEN concludes that past AER electricity DNSP decisions do not appear to be consistent in their adoption of labour productivity adjustments. However, JEN considers that the incorporation of productivity adjustment in its labour escalators is secondary to the much more important question of whether alternative labour cost forecasts produced by Access Economics can be considered more accurate than what it proposed. This issue is further discussed below.

Adjustments for EGW employees and other employees

As noted, the draft decision split JEN's internal labour into two components: specialist EGW employees and clerical and administrative labour, and derived a weighted average.

According to the draft decision, the AER defines EGW employees as 'specialist electrical industry employees undertaking direct project work'.[246]

JEN maintains its view (previously expressed to the AER)[247] that the AER's definition is inconsistent with the ABS definition of EGW employees and not one that JEN has previously applied. The ABS definition of an EGW business unit is as follows:

> The Electricity, Gas, Water and Waste Services Division comprises units engaged in the provision of electricity; gas through mains systems; water; drainage and sewage services.[248]

JEN considers the AER definition to be an arbitrary one which would lead to a significant miscalculation of JEN's true internal labour costs.

This view is confirmed by Econtech who analysed the AER's weighted average labour cost escalators. Econtech's description of the main issues is summarised below.

[245] BIS Shrapnel, op. cit. pp. A-4 and A-5.

[246] Draft decision, Appendix K, p. 134.

[247] Email from Anton Murashev (JEN) to Jeffrey Anderson (AER) dated 8 April 2010.

[248] Refer Chapter 8 of ANZSIC 2006 for full definition http://www.abs.gov.au/AUSSTATS/abs@.nsf/0/00C5F12D56E7B1B0CA25711F00146DA8?opendocument

Econtech analysis of AER weighted average labour costs calculations[249]

In addition to selecting an appropriate measure of labour costs (AWOTE vs. LPI), it is necessary to identify which sectoral index most reasonably reflects the labour costs of the DNSPs, based on the composition of their workforce.

The AER calculated separate labour cost escalators for internal labour costs and outsourced services labour costs. The AER calculated industry (for specialist workers) and the Victorian state LPI (for clerical/admin workers).

It is important to recognise that the LPI measure for each industry is comprised of a range of occupations that are shared between industries. As such, the LPI measure for the EGWWS industry is calculated based on the earnings of employees of businesses in that industry, meaning it includes occupations such as electricians and electrical distribution trades workers as well as accountants, legal professionals, specialist managers and other occupations involved in business administration i.e. the EGWWS measure already accounts for clerical/admin workers.

As a result, Econtech conclude:[250]

> By taking a weighted average between growth for the Electricity, Gas, Water and Waste Services industry and the all industry average, the AER has diluted internal labour cost forecasts for the DNSPs. Labour costs for the Electricity, Gas, Water and Waste Services industry have historically tended to grow at a faster rate than the all industry average.
>
> This trend is expected to continue over the regulatory period, with forecasts from BIS Shrapnel, Access Economics and KPMG Econtech all predicting Electricity, Gas, Water and Waste Services wages to grow at a faster pace than the all industries average. By including the all industries LPI in its calculation, it is likely that the AER has underestimated the true growth in labour costs faced by the DNSPs.
>
> We would also note that if the AER were to insist on calculating a weighted average based on the split between specialist and clerical/administrative staff, a weighted average of labour costs in the Electricity, Gas, Water and Waste Services industry, the Professional, Scientific and Technical Services industry and the Administrative and Support Services industry would be more reflective of the true labour costs of the DNSPs than a weighted average based on the all industries LPI for Victoria.

Econtech add that:

[249] KPMG Econtech, *Assessment of the AER's Draft Decision on Labour Cost Escalation: Victoria,* 13 July 2010, pp. iv-v.

[250] KPMG Econtech, op. cit. p. 25.

> We note that following the weighted average approach described above, it is not possible to replicate the AER's real labour cost escalator results reported in Table K20 of the draft decision appendices using Access Economics' real LPI forecasts from its March 2010 report.

In summary, JEN submits that the Econtech analysis above fully supports JEN's view that the AER's weighted average calculation of internal labour costs is incorrect. Applying this calculation to JEN's internal labour would lead to a significant miscalculation of JEN's true internal labour costs by double-counting as a result of an arbitrary allocation of costs by the AER. JEN submits that the ABS definition of EGW costs should be adhered to in forecasting internal labour costs, as both BIS Shrapnel and Econtech have done.

AER's treatment of outsourced labour costs.

While the AER accepted BIS Shrapnel's methodology for outsourced labour, the AER considered it important to utilise the most recently available data, which was that of Access Economics. However, the latter did not include a specific LPI forecast for the 'property and business services' sector as BIS Shrapnel had done. Notwithstanding this, the AER considered that the Access Economics general labour cost forecasts were a reasonable proxy.

Econtech has analysed the AER methodology for outsourced labour. Econtech's description of the main issues is summarised below.

Econtech analysis of AER outsourced labour costs calculations[251]

> The AER substituted forecasts of the all industries LPI in Victoria in place of a measure based on the Property and Business Services industry. These were combined with Construction sector wage forecasts developed by the Construction Forecasting Council (**CFC**), which were more up to date than the Access Economics Construction LPI forecasts.
>
> There are two issues in this approach:
>
> - the nature of the CFC forecasts
> - the use of general labour cost forecasts as opposed to labour cost forecasts for the Property and Business Services sector.
>
> In relation to the first point, the CFC forecasts are not forecasts of labour costs or wages for the CFC. The CFC forecasts are developed on a bi-annual basis by KPMG Econtech. The forecasts project price indices for

251 KPMG Econtech, op. cit. pp. 27-9.

three broad categories of construction activity; residential, non residential and engineering construction.

As such, *the AER incorrectly applied output price forecasts from the CFC website, in place of using wage cost forecasts*. Further, the indices are not state specific but apply to Australia as a whole.

The implication of this miscalculation is that the AER's outsourced services labour cost escalator is likely to be too low. The AER's outsourced services labour costs escalator is expected to underestimate the true growth in outsourced services labour costs of the DNSPs.

In relation to the second point, the AER justified the substitution of the all industries forecasts for Property and Business Services forecasts on the basis that the all industries forecasts are a reasonable proxy, and that movements in labour costs for Property and Business Services would be similar to the all industries average.

Although 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 cost escalators that most reasonably reflect likely changes in labour costs over the forecast period.

On this basis, it may be prudent for the AER to source up to date forecasts of labour cost growth for the Property and Business Services industry, or similar industries that are specified under the ANZSIC 2006 classification (Property and Business Services is defined under the old ANZSIC 1993 classification).

In summary, JEN notes that Econtech has identified a major error in the draft decision's application of the CFC forecasts which is likely to underestimate the true growth in JEN's outsourced services labour costs. The substitution of Access Economics' general labour forecasts for Property and Business Services is still an incorrect application of a labour cost escalator to JEN's likely future costs.

Access Economics forecasts and methodology

Given the draft decision's total reliance on Access Economics labour forecasts, it would be reasonable for the AER to demonstrate that Access Economics modelling methodology and its track record on forecast accuracy was at least equal to other forecasters, such as BIS Shrapnel and Econtech. However, JEN notes that there is a notable lack of transparency with Access Economics modelling; for example, it is not possible to determine how Access Econcomics adjusted wages escalators for productivity.

Both Econtech and BIS Shrapnel have reviewed aspects of Access Economics methodology and have noted the lack of transparency.

KPMG Econtech states:

> This lack of transparency represents a departure from the high standards upheld by the AER in past determinations, such as the transmission determination for Victoria and distribution determination for New South Wales. For those determinations, the AER engaged KPMG Econtech to develop labour cost forecasts; our reports provided a full step-by-step explanation of the forecasting methodology and equations that were used to convert ABS data into modelling inputs. We would recommend that the AER request further detail on Access Economics' modelling approach, to provide greater transparency in the forecasting methodology and allow for a complete assessment of Access' findings.[252]

BIS Shrapnel was commissioned by the Victorian DNSPs to review Access Economics' utilities wage model, and this is attached as Appendix 8.4 in this revised regulatory proposal.[253] BIS Shrapnel's observations are summarised below.

> Without having access to AE's macroeconomic model of the national economy, we cannot assess the robustness of the AE national wage model. Nor can we estimate the model coefficients in order to check how closely the model approximates the national wage inflation. Second-guessing model construction (the way the variables are linked) and its underlying theoretical foundations, database used and the estimation technique employed in order to replicate the model estimates and to generate the forecasts would be a futile exercise. Descriptive background information that is provided in the report is not sufficient given the large number of variables that are considered in large-scale macroeconomic models.[254]

BIS Shrapnel has endeavoured to generate the historical (in-sample) utilities wage escalation using the Access Economics methodology. The objective is to determine how well Access Economics approximates the underlying (actual) data generating process. BIS Shrapnel states that for the Access methodology to be credible, its model generated historical estimates should show close resemblance to the actual observed data:[255]

> While one can apply several diagnostic techniques to check how well the model fits the data, perhaps the best way to see how well AE model explains the underlying data generating process is by plotting the in-sample model estimates against the

252 KPMG Econtech, op. cit. pp. 23.

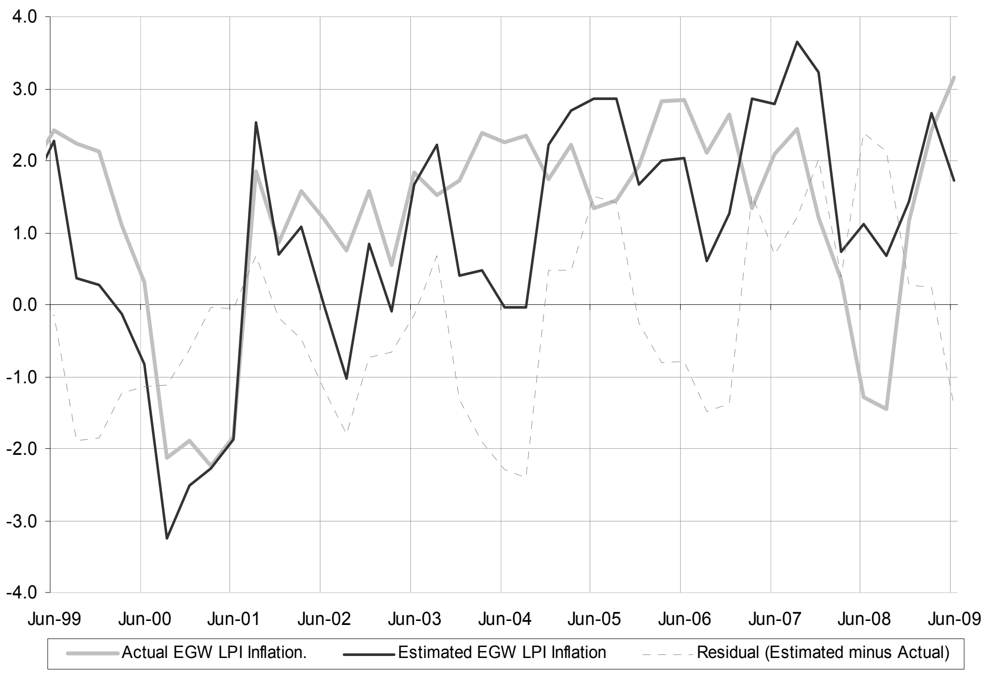
253 BIS Shrapnel: *Review of Access Economics' Utilities Wage Model - Prepared by BIS Shrapnel for the Victorian Electricity Distributors*, July 2010.

254 BIS Shrapnel, op. cit. p. 3.

255 BIS Shrapnel, op. cit. pp. 6-7.

actual EGW wage escalation. A chart which plots these variables together with the forecast error (as estimated by model residuals) is provided below.

Figure 8-4: BIS Shrapnel Chart 3.3: Real EGW LPI v Model Predictions



Source: BIS Shrapnel & ABS Data

As can be seen from chart 3.3, the AE model does a poor job in approximating the observed wage escalation in the EGW sector. Residuals are significantly different from zero and therefore cannot be dismissed as 'white-noise' or a zero mean process. Chart 3.3 also reveals that for the majority of the sample, AE model understates the actual wage escalation in the EGW sector.

BIS Shrapnel concludes that the limitations highlighted in Access Economics modelling approach means that Access fails to adequately model the wage inflation in the EGW sector. In BIS Shrapnel's view, the Access Economics model therefore should be dismissed as a forecasting tool for labour cost escalation for the EGW sector.[256]

Econtech also notes significant concerns with Access Economics modelling, particularly their macroeconomic assumptions:[257]

[256] BIS Shrapnel, op. cit. p. 7.

[257] KPMG Econtech, op. cit. pp v-vi.

> A consideration of the underlying macroeconomic forecasts used to drive labour costs is essential in assessing the accuracy and robustness of the resulting LPI forecasts. Of most interest are forecasts of overall economic growth, as indicated by Gross Domestic Product (GDP).
>
> A comparison of growth rates in the short run shows that Access Economics outlook is pessimistic in comparison to the RBA and KPMG Econtech. Indeed, Access does not expect growth to lift substantially above normal ….until 2012, with a full recovery not taking place until 2013. This is in contrast to the RBA and KPMG Econtech, who both forecast strong growth in 2011.
>
> Overall, Access Economics' short run GDP forecasts are pessimistic in comparison to other forecasts. This would suggest that Access' forecasts are at the bottom of the range of reasonable expectations of future economic growth, an issue that should be taken into consideration by the AER in making its final decision.

From the above analyses, JEN submits that Access Economics labour cost forecasts offer no advantages over forecasts produced by BIS Shrapnel and Econtech and on balance may well be inferior. Given the tendency of Access Economics modelling to understate labour cost growth (as identified by BIS Shrapnel), JEN belives that the forecasts produced by Access Economics are not consistent with the Rules in produing a realistic expectation (clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the Rules). The noted lack of transparency in Access Economics modelling further reduces confidence in its forecasts.

JEN updated labour cost escalators

JEN is proposing to use averages of the latest BIS Shrapnel and Econtech labour cost forecasts, in accordance with the AER's preference for using the most recent forecasts available.

JEN's escalators have been derived from two sources:

- BIS Shrapnel: *Wages Outlook for the Electricity Distribution Sector in Victoria - Prepared by BIS Shrapnel for the Victorian Electricity Distributors*, July 2010 (see Appendix 8.5)
- KPMG Econtech: *Labour Cost Forecasts for Powercor and CitiPower*, 13 July 2010 (see Appendix 8.7).

JEN's escalators were calculated as follows:

Internal labour

This was calculated as a simple average of AWOTE EGW wages (taken from table 1.1 of the BIS Shrapnel report) and EGW average weekly earnings (taken from table 2 of the Econtech report). From BIS Shrapnel's report, JEN used the real escalator in table 1.1. From Econtech's report, JEN used the nominal escalator in table 2, and converted it to real using JEN's inflation forecast based on the AER's preferred methodology.

External labour

This was calculated as the average of:

BIS Shrapnel's Outsourced Services Wage Escalator (real) taken from table 1.1 of the BIS Shrapnel report; and a combined escalator comprising:

- construction average weekly earnings (taken from table 3 of the KPMG Econtech report)
- administration and support services average weekly earnings (taken from table 5 of the Econtech report).

JEN converted Econtech's nominal escalators to real, using the same method as for internal labour.

JEN has set out all the above calculations in Appendix 18.3.

The resulting labour escaltors

Table 8-5 shows JEN's forecast real labour cost escalators.

Table 8-5: JEN real labour cost escalators (per cent)

Escalator	2010	2011	2012	2013	2014	2015
Internal labour	6.05	2.54	3.29	3.37	2.89	2.68
External labour	4.12	1.79	2.21	2.35	2.09	1.89

Use of updated escalator forecasts in AER decisions

In the draft decision the AER has indicated that it has a preference to update information in relation to cost escalators closer to the date of the final decision.[258] Implicit 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 recent decision of the Australian Competition Tribunal

[258] AER, op.cit. p. 115.

relating to the selection of the period for the measurement of the risk free date and the debt risk premium indicates that this premise is not necessarily correct.[259]

An important purpose of the draft decision is to inform the relevant service provider of the determination of the AER in relation to the service provider's revised regulatory proposal. In response to the draft decision, JEN is entitled to submit a revised regulatory proposal to the AER which may incorporate amendments necessary to address the matters raised in the daft decision.

One relevant circumstance is the decision-making regime in which: JEN puts forward its regulatory proposal; this is assessed by the AER in a draft decision; JEN is then entitled to submit additions or other amendments to the revised regulatory proposal to address matters raised in the draft decision as well as make a submission on the draft decision; and the AER makes a final decision. In order for JEN to properly participate in the decision making process of the AER, and for the draft decision to serve a real purpose, as a general statement, the last time at which the AER should update forecasts is as part of the regulatory proposal revision process.

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. Such an approach is: inconsistent with the decision of the Tribunal in Application by EnergyAustralia and Others and does not give real meaning to the role of the AER's draft decision.

To the extent the AER concludes that, contrary to the above, it is appropriate to update any forecasts as part of its final decision, these forecasts should be provided to JEN a sufficient time prior to the final decision to allow JEN to consider and, if necessary, respond to those forecasts.

8.12 Revised non-labour escalators

8.12.1 Summary of JEN's original regulatory proposal

To better reflect trends in raw material and other material prices leading to real increases in the costs of network components, Sinclair Knight Mertz (**SKM**) was commissioned jointly by the Victorian distributors to produce a set of escalators for the forthcoming regulatory control period. JEN notes that, while its regulatory proposal cited only steel and aluminium escalators, it applied all the escalators developed by SKM in its opex and capex modelling (as referenced in the draft decision).[260]

259 *Application by EnergyAustralia and Others (2009) ATPR 42-299*, [90].

260 Draft decision, Appendix K, p. 117.

8.12.2 Summary of AER's draft determination and decision

The AER's draft decision did not accept JEN's proposed non-labour escalators and substituted its own escalators as follows:[261]

Table 8-6: AER draft decision JEN non-labour cost escalators (per cent annual change unless noted otherwise)

Escalator	2010	2011	2012	2013	2014	2015
Aluminium	39.82	7.16	1.40	-3.33	-5.35	-5.99
Copper	51.53	2.99	-3.27	-7.63	-9.86	-10.91
Steel	25.15	7.54	2.08	-1.08	-2.86	-3.48
Crude oil	40.17	7.74	-0.28	-1.58	-2.84	-3.14
Exchange rate ($A/$US)	0.719	0.739	0.726	0.728	0.737	0.749
Wood poles	0.00	0.00	0.00	0.00	0.00	0.00
Inverse of TWI and CPI	0.00	0.00	0.00	0.00	0.00	0.00
Construction costs	1.17	0.51	1.94	2.79	1.74	-0.05

AER reasons for not accepting JEN forecasts

Aluminium, copper, steel and crude oil

- The AER acknowledged that the method proposed by SKM to forecast the escalation of aluminium, copper, steel and crude oil costs for the Victorian DNSPs was broadly consistent with the method allowed by the AER in recent decisions for other DNSPs.[262]

- However, the AER was not satisfied that the approach SKM had taken to forecast the exchange rates used to restate the USD based market prices of aluminium, copper and steel provided a realistic expectation of cost inputs. In addition, the AER considered that to develop a robust forecast it was appropriate to update the forecast materials cost escalators using the most recent data.[263]

[261] Draft decision, Appendix K, pp. 120-45.

[262] Draft decision, Appendix K, pp. 119-23.

[263] Draft decision, Appendix K, pp. 119-23.

Exchange rates

The AER was not satisfied with SKM's approach that used historical data to prepare exchange rate forecasts, because:

- it did not reasonably reflect the capex and opex criteria
- Econtech's Australian National State and Industry Outlook (ANSIO) report is a credible source for providing exchange rate forecasts.

Accordingly, the exchange rates developed by the AER to convert materials forecasts and prices from USD to AUD interpolated historical exchange rates from the RBA with Econtech ANSIO exchange rates.[264]

Carbon costs

The draft decision concluded that the cost escalators adopted by the Victorian DNSPs should not include any explicit consideration of the CPRS.[265]

Wood poles

The AER's draft decision concluded that the cost escalators adopted by the Victorian DNSPs should not include any real escalation for wood poles.[266]

Trade weighted index

The draft decision did not consider it reasonable to escalate the cost of imported equipment for a movement in the TWI.[267]

Construction costs

- the AER noted that SKM applied engineering construction cost forecasts sourced from the CFC's website, which is consistent with the application of construction cost forecasts in recent AER distribution determinations
- the AER did not, however, consider that the geometric average of two financial periods when determining the calendar year pricing positions is reasonable. The AER considered that the use of financial year escalators cannot be reasonably used to approximate a calendar year escalator.[268]

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264 Draft decision, Appendix K, pp. 124-5.

265 AER, op. cit. p. 140.

266 AER, op. cit. p. 142.

267 AER, op. cit. p. 143.

268 Draft decision, Appendix K, pp. 144-5.

8.12.3 Application of real cost escalators in the draft decision

The draft decision noted that without SKM's model, the AER had been unable to escalate the Victorian DNSPs' opex and capex proposals by the labour and materials escalators determined in accordance with the draft decision (as described above). According to the draft decision, the AER used earlier SKM weightings (supplemented by DNSP advice requested by the AER) to arrive at real weighted opex and capex escalation rates for each DNSP.[269]

As a result, the AER determined for JEN:

- weighted opex real escalation rates (table K.30 of Appendix K)[270]
- weighted capex real escalation rates (table K.33 of Appendix K).[271]

The draft decision states:

> 'The AER will require the Victorian DNSPs to provide the weightings of each of the labour and materials escalators in their capex programs. The AER will use this information in determining the amount or real cost escalation for each of the Victorian DNSPs in its final decision.'[272]

8.12.4 JEN's response to AER's draft determination and decision

JEN in conjunction other Victorian DNSPs engaged SKM to update the real materials cost escalation rates supplied to the Victorian DNSPs for their initial revenue proposals, with consideration of the AER's assessment of real cost escalation as published in its draft decision (see Appendix 8.3).[273] In the following sections, JEN summarises the SKM recommendations and the updated escalators supplied by SKM. JEN addresses each material escalator covered in the draft decision. However, the escalators are applied in JEN's modelling as composite (weighted) escalators applicable to various asset classes. JEN has applied the asset escalators in Appendix A of the SKM report.

Aluminium, copper, steel and crude oil

For these materials, the AER was not satisfied that the approach SKM had taken to forecast the exchange rates used to restate the USD based market prices of

269 AER, op. cit. p. 146.

270 AER, op. cit. p. 149.

271 AER, op. cit. p. 152.

272 AER, op. cit. p. 149.

273 SKM, *Victorian Distribution Network Service Providers cost escalator updates: Final Report – Jemena / United Energy Asset Categories*, 8 July 2010.

aluminium, copper, steel and crude oil provided a realistic expectation of cost inputs.

SKM now consider that:

> SKM would recommend including the foreign exchange forecast put forward by the AER in its draft decision, as it is also SKM's preferred source for this information.[274]

JEN accepts this recommendation, which incorporates the draft decision:

- *Exchange rates* – As noted above, SKM has incorporated the foreign exchange forecast used by the AER in its draft decision. This therefore incorporates the draft decision.

- *Carbon costs* – The draft decision concluded that the cost escalators adopted by the Victorian DNSPs should not include any explicit consideration of the CPRS. SKM notes that the updated cost escalation rates attached as Appendix A incorporate the changes to align with the draft decision, including no CPRS / carbon component.[275] JEN has therefore incorporated the draft decision.

- *Wood poles* – The AER's draft decision concluded that the cost escalators adopted by the Victorian DNSPs should not include any real escalation for wood poles.JEN notes that the asset escalators provided by SKM do not incorporate any real cost escalation for wood poles.[276] JEN has therefore incorporated the draft decision.

- *Trade weighted index* – The draft decision did not consider it reasonable to escalate the cost of imported equipment for a movement in the TWI.JEN notes that SKM now recommend no application of the TWI, which only affects historic years (base year to current).[277] JEN has therefore incorporated the draft decision.

- *Construction costs* – The AER did not consider that the geometric average of two financial periods when determining the calendar year pricing positions is reasonable. JEN notes that SKM's construction cost escalator still retains its previous averaging methodology (no quarterly disaggregation). SKM's reasons are explained in its report.[278]

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274 SKM, op.cit. p. 4.

275 SKM, op.cit. p. 14.

276 Ibid.

277 Ibid.

278 SKM, op.cit. pp. 11-12.

8.12.5 Update to the JEN access arrangement information

JEN has not incorporated the AER draft decision Table 7.17 and draft decision tables K.30 and K.33 in Appendix K in respect of escalators. Instead, JEN has applied the updated labour and materials escalators prepared by BIS Shrapnel, Econtech and SKM. These updated escalators are set out in Table 8-7 below. JEN considers that these escalators are consistent with clauses 6.5.7(c)(3) and 6.5.7(c)(3) of the Rules and represent forecasts that are a realistic expectation.

Table 8-7: **JEN's revised real escalators to account for updated data**[279]

Escalator	2010	2011	2012	2013	2014	2015
Internal labour	6.05	2.54	3.29	3.37	2.89	2.68
External labour	4.12	1.79	2.21	2.35	2.09	1.89
Aluminium	26.30	19.60	-0.30	-1.50	-3.50	-3.30
Copper	35.20	14.90	-4.90	-6.00	-8.10	-8.20
Steel	21.40	12.60	-4.70	-0.40	-1.60	-1.40
Crude oil	15.40	16.50	-0.70	0.10	-1.60	-1.20
TWI (inverse)	0.00	0.00	0.00	0.00	0.00	0.00
Wood poles	0.00	0.00	0.00	0.00	0.00	0.00
Construction costs	-0.10	-0.20	1.30	1.90	0.70	-0.80

8.13 Other specific issues raised in the draft decision

8.13.1 Commercial margin

JEN has not incorporated the AER's amendment to remove the commercial margin payable to JAM under the AMA. JEN's response to the draft decision conclusions on this margin are set out in section 6.3.

8.13.2 Overheads

JEN has incorporated the AER's amendment to include overheads based on the level JEN has historically incurred. To achieve this, JEN has forecast its direct and indirect capitalised corporate overheads using a base year roll forward method similar to that employed for opex forecasting.

279 The escaltors have been sourced from SKM report p. 15 and have been rounded. Actual modelling uses more precise figures.

JEN has taken its 2009 Regulatory Accounts data for direct and indirect overheads and has applied input cost escalation for labour and materials over the forecasting period. Appendix 18.7 provides this calculation and the resulting capitalised overheads forecast.

8.13.3 Equity raising costs

The AER's draft decision provided JEN with no forecast equity raising costs based on the AER's preferred forecasting method and the forecast capex and forecast cost of service determined by the AER. This meant the AER rejected JEN's forecast equity raising costs.

JEN's revised forecasts for capex and cost of service require JEN to also revise its forecast equity raising costs. Based on the new forecast cost of service, equity raising cost assumptions and capital plan, JEN estimates that it can cover its equity raising requirements through retained earnings alone.

Despite this current estimate, JEN considers that equity raising costs are legitimate expenses that should be recoverable through its standard control prices. If, in its final decision, the AER amends JEN's forecast cost of service, equity raising costs assumptions or capital plan, JEN proposes that this estimate be updated and reovered accordingly.

JEN has largely employed the AER's draft decision method for forecasting equity raising costs based on its revised capital plan and cost of service forecast. The only exception relates to the AER's assumed dividend payout ratio. Where the AER has assumed a 100 per cent pay out ratio, JEN has assumed a 70 per cent pay out ratio for the reasons set out in its gamma discussion at section 12.3.

JEN proposes to capitalise equity raising costs to its RAB using benchmark costs for an efficient gas network:

- 1 per cent on equity raised internally through dividend reinvestment
- 3 per cent on equity raised externally.

These benchmarks reflect the AER's draft decision. JEN includes its proposed calculation of equity raising costs in the 'Equity Raising Costs' sheet of Appendix 18.1. It ensures that equity raising costs are capitalised to JEN's opening 2011 RAB if the retained earnings cash flow is not sufficient to cover the equity needed to fund JEN's capital plan.

8.14 Bottom up asset management capex plan

JEN has revised its bottom up asset management capex plan over 2011-2015, taking account of the AER's concerns raised in its draft decision and those by

Nuttall, and changes in conditions since JEN's November 2009 regulatory proposal.

Table 8-8 sets out JEN's bottom up asset management capex plan.

Table 8-8: JEN's revised bottom up asset management capex plan

Item	2011	2012	2013	2014	2015	Total
Network assets	81.8	89.4	97.1	104.6	113.4	486.4
Non-network assets	19.5	24.3	7.7	4.6	6.3	62.3
Total excluding IT	**101.3**	**113.7**	**104.8**	**109.2**	**119.7**	**548.7**

The major factors influencing JEN's bottom up asset management capex plan are:

- increasing maximum demand, which in broad terms has increased 17.8 per cent over the current regulatory control period. This has led to a network-wide increase in asset utilisation which has increased the numbers of individual assets operating above their design ratings. The revised capex forecast reflects an update to the demand forecast as requested by the AER to include latest gross state product data and policy impacts (see chapter 5). JEN has also fully reconciled its own bottom-up peak demand forecasts and the NIEIR's top-down forecasts (see chapter 5).

- a review of all of JEN's asset replacement models to validate inputs and outputs (see Appendix 8.2]

- preparation of supporting business cases and strategic planning papers (see Appendices 8.10 to 8.38).

8.14.1 Features of JEN's bottom up asset management capex plan

Since November 2009 the following changes have occurred which impact on JEN's bottom up asset management capex plan.

Progress with detailed designs and cost estimates

In the time between submitting JEN's original regulatory proposal and preparing this revised regulatory proposal, a number of projects have progressed through the gating process. As a result, more information, including more accurate costing information and business cases are now available for a number of JEN's proposed capital projects. JEN has provided a confidential sample set of these businesses cases in Appendices 8.10 to 8.38.

JEN's bottom up asset management capex plan reflects the more accurate and up-to-date estimates. JEN believes that this should address Nuttall's concerns that project costs would be optimised.

Introduction of strategic planning papers

JEN has introduced a strategy document between the NAMP and Gate 1 to provide a strategic overview of either an asset class (RQM and ESL) or a geographic region (reinforcement). The purpose of the strategic planning paper bridges the gap between the concepts in the NAMP and the detail of individual project business cases. A typical strategic planning paper will include:

- a statement of the objectives for the assets
- analysis of the engineering, commercial and regulatory issues facing either the asset class or the region
- a statement of the reasons for why the management of the assets (or region) needs to change
- consideration of the "do nothing", "non-network" and "network" options, along with a description of the likely consequences and an assessment of the prudency
- a broad description of the chosen option, along with likely costs and work volumes (that will lead into the business plan).

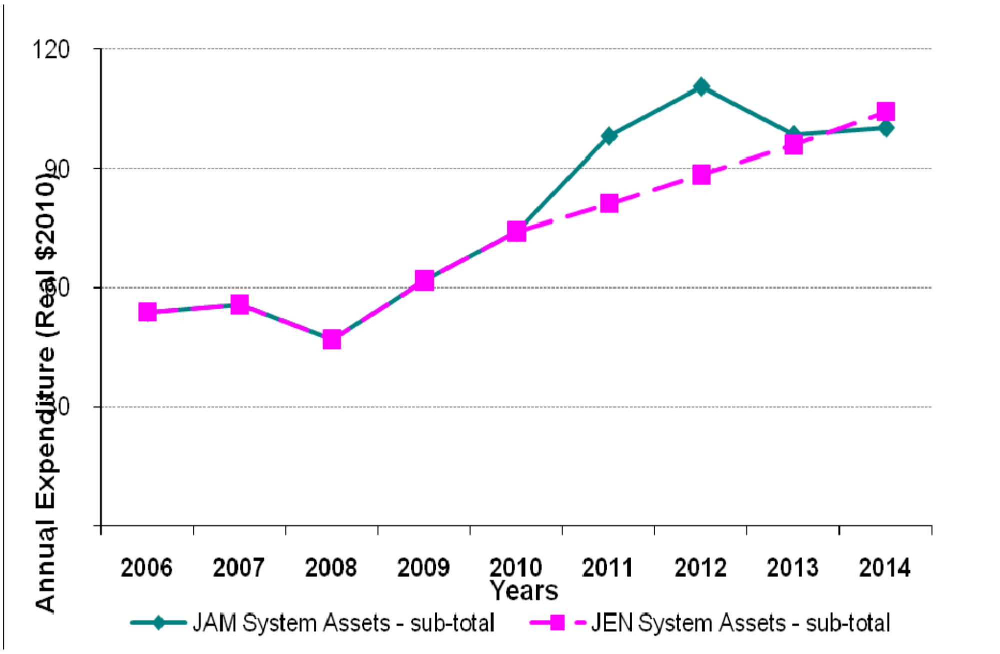
8.15 JEN's revised capex forecast

JEN has considered the bottom up asset management capex plan. JEN proposes to adopt a smoothed expenditure forecast, based on management's review of the bottom-up developed asset management program proposed by JAM and taking into consideration the observations made by AER in its draft decision.

Management has reconsidered the spend profile and agrees with the AER that a step change in expenditure may not be practical. JEN has also scaled back some elements of the bottom-up revised asset management plan based capex program. Although this will further delay the desired levels of replacement expenditure and introduce new risks, JEN believes that these risks are manageable and more than offset by the benefits of avoiding inefficiencies and risks associated with trying to increase capital expenditures too rapidly. In addition, this risk will be reduced through the satisfactory completion of the proposed five year program.

As illustrated in the following graph, the expenditure profile indicated by the bottom-up asset management plan required a large shift in expenditure between 2010 and 2013. JEN proposes a smoothed program as shown in the graph below.

Figure 8-5: JEN system assets capex



The resulting JEN revised capex forecast removes the significant step change from JAM's recommended asset management forecast, and therefore will avoid inefficiencies. The smoothed plan proposes an expenditure program which is consistent with the average annual increase in capital works since 2006. By continuing to take this approach, JEN can be confident to deliver the program over the period and ensure appropriate levels of long-term sustainable capital expenditure.

Table 8-9 reconciles JEN's revised forecast capex with that proposed in its original regulatory proposal.

Table 8-9: JEN revised forecast capex

Item	2011	2012	2013	2014	2015	Total
Reinforcement						
Nov 2009 regulatory proposal	28.8	39.7	37.7	34.5	31.1	171.7
Revised regulatory proposal	20.6	26.0	26.6	28.1	26.8	128.1
Difference	-8.3	-13.7	-11.1	-6.3	-4.2	-43.6
Reliability and quality maintained						
Nov 2009 regulatory proposal	35.9	33.5	33.7	39.6	42.6	185.3
Revised regulatory proposal	26.6	26.0	29.5	35.2	41.8	159.1

Item	2011	2012	2013	2014	2015	Total
Difference	-9.4	-7.5	-4.1	-4.4	-0.8	-26.2
Environmental, safety and legal						
Nov 2009 regulatory proposal	5.8	9.2	7.3	5.5	5.1	32.9
Revised regulatory proposal	7.4	9.8	7.2	5.9	5.7	36.0
Difference	1.6	0.6	-0.1	0.4	0.7	3.1
SCADA and network control						
Nov 2009 regulatory proposal	0.8	1.2	1.2	0.3	0.0	3.6
Revised regulatory proposal	0.7	0.9	1.2	0.3	0.0	3.1
Difference	-0.2	-0.3	-0.0	0.0	0.0	-0.5
Non-network IT						
Nov 2009 regulatory proposal	20.2	21.1	17.2	6.6	6.8	71.9
Revised regulatory proposal	20.3	21.0	17.2	6.6	6.8	72.0
Difference	0.1	-0.1	0.0	0.0	0.0	0.1
Non-network other						
Nov 2009 regulatory proposal	19.8	9.4	7.8	4.6	6.3	47.9
Revised regulatory proposal	19.5	24.3	7.7	4.6	6.3	62.3
Difference	-0.3	14.9	-0.1	-0.0	-0.1	14.4
Customer connections						
Nov 2009 regulatory proposal	28.1	29.3	31.1	32.8	34.5	155.8
Revised regulatory proposal	26.6	26.7	32.6	35.1	39.1	160.0
Difference	-1.5	-2.6	1.4	2.3	4.6	4.2
Total						
Nov 2009 regulatory proposal	139.6	143.4	136.0	123.9	126.3	669.2
Revised regulatory proposal	**121.6**	**134.7**	**122.0**	**115.8**	**126.5**	**620.7**
Difference	-17.9	-8.7	-14.0	-8.1	0.2	-48.5

8.16 Compliance with the Rules

JEN's revised capex forecasts are made on a reasonable basis and have been developed to comply with the capex objectives and criteria, and to address the capex factors specified in clauses 6.5.7(a), (c) and (e) of the Rules respectively.

8.16.1 AER / Nuttall Consulting approach – compliance with the Rules

Overview of the Rules

As noted in section 1.4.2, clause 6.12.3 of the Rules mandates the AER's use of a fit-for-purpose decision-making framework, and in respect of capital and operating expenditure, a propose–respond decision-making framework.[280] In the context of a service provider's forecast capex, clause 6.12.3, together with clauses 6.5.7 and 6.12.1 sets out the approach the AER is required to adhere in making a distribution determination.

Clause 6.12.1 sets out that a distribution determination is predicated on a number of decisions (constituent decisions) by the AER, including, most relevantly, a decision in which the AER either:

- acting in accordance with clause 6.5.7(c), accepts the total of the forecast capital expenditure for the regulatory control period that is included in the building block proposal; or

- acting in accordance with clause 6.5.7(d), does not accept the total of the forecast capex for the regulatory control period that is included in the current building block proposal. In this instance, the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required capex for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors.

In short, the AER's decision in relation to forecast capex must be in accordance with either clause 6.5.7(c) or clause 6.5.7(d).

Clause 6.5.7(c) provides that the AER must accept a service provider's forecast capex where those forecasts meet the capital expenditure criteria, namely that the forecasts reasonably reflect:

- the efficient costs of achieving the capital expenditure objectives

- the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capital expenditure objectives

- a realistic expectation of the demand forecast and costs inputs required to achieve the capital expenditure objectives.

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280 Ministerial Council on Energy, *Principle Rules Changes from 1st Exposure Draft*, Energy Market Reform Bulletin No. 105, 5 October 2007, p. 1.

Clause 6.5.7(d) states that the AER must not accept a service provider's forecast capital expenditure if it is not so satisfied.

Clause 6.12.3 relevantly provides:

- that subject to clause 6.12.3 and other provisions of Chapter 6 explicitly negating or limiting the AER's discretion, the AER has a discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal
- if the AER refuses to approve an amount or value referred to in clause 6.12.1 (constituent decisions), the substitute amount or value on which the distribution determination is based must be:
  - determined on the basis of the current regulatory proposal
  - amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

It is evident from the Rules that in assessing a service provider's capex allowance, the threshold question the AER must first determine is whether or not the service provider's forecast capital expenditure meets the capital expenditure criteria (**Capex Criteria Decision**).

If, and only if, the AER decides that the service provider's forecast capex does not meet the capital expenditure criteria does it have the ability to determine substitute amounts. The ability of the AER to determine substitute amounts is further guided by the requirements of the Rules which provide that the AER can only determine substitute amounts on the basis of the service provider's regulatory proposal. The AER is only permitted to depart from that basis to the extent necessary to enable the amount to be approved in accordance with the Rules (**Substitute Expenditure Decision**).

AER non-compliance

As outlined above, the Rules require that the AER firstly assess a service provider's proposal in order to make the Capex Criteria Decision. It is only when the outcome of the Capex Criteria Decision is that the AER is not satisfied that the service provider's forecast capex reasonably reflects the capital expenditure criteria, that the AER can make the Substitute Expenditure Decision.

Further, in making the Substitute Expenditure Decision the regulator must arrive at the substitute amount on the basis of the service provider's proposal. If the amount arrived at using that basis does not reasonably reflect the capital expenditure criteria, the AER can amend the amount, but only to the extent necessary to enable it to be approved under the Rules.

JEN considers that the AER has failed to adhere to the fit-for-purpose decision-making framework (and the propose-respond elements of that framework with respect to capital expenditure) in making its draft distribution determination. In particular, in relation to individual capex categories proposed by JEN, the AER has:

- incorrectly applied the capex criteria in making the Capex Criteria Decision – in particular, the AER (and Nuttall) has in several instances commenced its assessment with an assumption that recent historical levels of capital expenditure represent an efficient cost base as opposed to a genuine assessment of whether JEN's proposal meets the capital expenditure criteria

- failed to make the Substitute Expenditure Decision – in particular, the AER has in several instances adopted an entirely different basis to the bottom-up approach adopted by JEN in forecasting its capital expenditure. In starting at the wrong place, the AER has then also necessarily failed also to amend JEN's proposal only to the extent necessary to enable it to be approved in accordance with the Rules.

Incorrectly applying capex criteria in making the Capex Criteria Decision

The AER and Nuttall have both incorrectly applied the capex criteria in making the Capex Criteria Decision in several instances. By starting from an unsupported and incorrect assumption that recent historical levels of actual expenditure represent an efficient cost base, the AER has failed to properly consider:

- whether a service provider's forecast capex reasonably reflects the efficient costs of achieving the capital expenditure objectives (**first capex criteria**)

  by instead considering:

- whether a service provider's forecast capex is in line with recent historical levels of actual expenditure.

By incorrectly applying the first capex criteria, the AER and Nuttall have also tainted the subsequent analysis of whether or not a service provider's forecast reasonably reflects the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capital expenditure objectives (**second capex criteria**). This arises because the AER and Nuttall purported consideration of the second capex criteria is principally guided by its analysis of recent historical levels of capital expenditure.

In particular, in relation to the following capex categories, JEN makes the following submissions.

- *Reinforcement* – The stated approaches of both the AER and Nuttall is to assume that the current level of capex is a representation of an efficient base to forecast augmentation expenditure[281], and their stated conclusions are that 'each DNSP has not adequately justified that the proposed increases in forecast reinforcement expenditure reasonably reflects the capex criteria'.[282] This approach reflects a fundamental misunderstanding of the nature of capex – in that past levels of expenditure of a capital nature have no logical bearing on the level of expenditure in future years (ie that expenditure is 'lumpy' in nature). Although the AER raises some relevant concerns about forecasting methodology, this does not disturb the inappropriate assumption upon which both the AER and Nuttall assessments of the first and second capex criteria are based. Accordingly, both the AER and Nuttall have incorrectly applied first and second capex criteria in making the Capex Criteria Decision.

- *Reliability and Quality Maintained* – It is clear that both the AER and Nuttall have approached the review of JEN's capex on the basis that current levels of expenditure are assumed to represent an efficient base, and that all significant increases in expenditure need to be justified as prudent and efficient.[283] In particular, where Nuttall has rejected JEN's proposed expenditure for certain activity codes, the underlying reason has been that the propose expenditure amount is significantly larger than the historical spend – and that such an increase has not been adequately justified.[284] Similarly, the AER has focused its review on areas where significant increases in expenditure have been proposed, with its formulaic considerations indicating a predisposition to consider all substantial increases in expenditure as prima facie not efficient and prudent.[285] This approach reflects a fundamental misunderstanding of the nature of capex – in that past levels of capex have no logical bearing on the level of expenditure in future years (that is, that expenditure is "lumpy" in nature). By assuming that the current level of expenditure represents an efficient base, the AER and Nuttall have incorrectly applied the first and second capex criteria in making the Capex Criteria Decision.

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281 Draft decision, p. 313; Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 10.

282 Draft decision, pp 335-6; Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 145.

283 Draft Decision, p. 339; Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, p. 10.

284 Nuttall Consulting, *Capital Expenditure: Victorian Electricity Distribution Revenue Review – A Report to the AER*, 4 June 2010, pp. 147-65.

285 Draft decision, p. 334.

- *Environment, Safety & Legal* – The AER's stated approach is to assume that the historical underlying trend in capex represents a starting point for assessing the reasonableness of a DNSP's (entire) capex proposal. In arriving at its conclusion, that it was not satisfied that the projects proposed by the DNSP reasonably reflected the capex criteria, the AER's assessment was focussed on the ELS capex incurred in the current and previous regulatory control periods. Noting that the DNSPs had not identified any changes in regulatory obligations or requirements to justify an increase in capital expenditure, the AER states that 'as the DNSPs are currently complying with their obligations, the associated costs will be reflected in the historical capex trend for this category'. The AER's assessment gives little consideration as to whether the forecasts meet the capital expenditure criteria set out in clause 6.5.7(c) of the Rules.

- *Non-Network IT* – In assessing JEN's proposed capex for the forthcoming regulatory period, both the AER and Nuttall have focussed on historical underlying capex trends, using it as a starting point for assessing the reasonableness of each DNSP's capex proposal. It is on this basis that Nuttall (and the AER) conclude that all the DNSPs had IT infrastructures that were too "static" and not sufficiently "agile" which would ultimately hinder the DNSP's ability to complete the IT projects proposed forthcoming regulatory period. As stated previously this approach reflects a fundamental misunderstanding of the nature of capital expenditure – in that past levels of capex have no logical bearing on the level of expenditure in future years. The approach adopted by Nuttall and the AER results in a flawed application and assessment of the capital expenditure criteria.

- *Non-network other* – Similar to its assessment of other capex categories, the AER has approached its assessment on the basis that the historical underlying trend in capex (data from 2004 to 2008) represented a starting point for assessing the reasonableness of each DNSP's capex proposal. In particular, the AER considered that the actual/out-turn expenditure represented the efficient capex amount. Again, this approach reflects a fundamental misunderstanding of the nature of capex – in that, in the absence of clear evidence to the contrary, past levels of capex have no logical bearing on the level of expenditure in future years.

Failure to make the Substitute Expenditure Decision

The AER has failed to make the Substitute Expenditure Decision in several instances by wholly adopting a basis that is foreign to the bottom-up basis adopted by JEN in forecasting expenditure. Clause 6.12.3 of the Rules requires that the AER depart from JEN's basis only to the extent necessary to enable the amount to be approved in accordance with the Rules. To the extent that the AER has generated substitute amounts using a basis that is completely foreign to the bottom-up basis used by JEN, the AER has failed to make the Substitute Expenditure Decision.

- *Reinforcement* – Nuttall's "weighted probability" approach to generate substitute expenditure amounts represents a wholesale departure from the bottom-up basis adopted by JEN. By adopting Nuttall's approach, the AER has started and ended its analysis by wholly departing from the basis adopted by JEN, and wholly adopting the approach used by Nuttall. It is clear that this method does not comply with Clause 6.12.3 of the Rules in that the AER is only permitted to depart from JEN's basis to the extent necessary to enable the amount to be approved in accordance with the Rules.

- *Reliability and Quality Maintained* – All adjustments made by the AER to JEN's forecast expenditure are stated to have been made by "subtracting the DNSP's forecast against the AER's repex modelling forecast".[286] That is, all the AER's adjustments to RQM expenditure have been made as per Nuttall's replacement expenditure model. It is clear that this method does not comply with Clause 6.12.3 of the Rules in that the AER has wholly departed from the basis adopted by JEN, and wholly adopted the approach used by Nuttall. The AER is only permitted to depart from JEN's basis to the extent necessary to enable the amount to be approved in accordance with the Rules.

- *Environment, Safety & Legal* – The AER's adopted an automatic continuation of the historical expenditure trend which JEN submits does not have adequate regard to the forward-looking nature of the capital expenditure objectives and capital expenditure criteria. This method does not comply with clause 6.12.3 of the Rules as the AER's substitute amount or value is not determined on the basis of JEN's regulatory proposal or amended from its regulatory proposal only to the extent necessary to enable its approval in accordance with the Rules.

- *Non-Network IT* – The AER's substitute expenditure amount is equal to JEN's proposed expenditure for 2011 – 2013 spread evenly across 2011-2015. In arriving at its substitute expenditure amount, the AER has principally relied on Nuttall's conclusion that JEN's IT architecture is not sufficiently agile. This conclusion is not supported by any relevant evidence.

- *Non-network other* – The AER does not appear to have set out clearly the approach that it has adopted in formulating its substitute expenditure amounts for JEN (which presumably relate only to JEN's vehicles and tools and test equipment expenditure categories). In this regard, the AER's draft

[286] Draft decision, p. 343.

decision does not satisfy the requirements of clause 6.12.2 (reasons for decisions), which requires the AER to set out the basis and rationale for its determination (including the details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the AER).

8.16.2 Compliance with capex objectives in clause 6.5.7(a) of the Rules

Notwithstanding where JEN has incorporated the AER's draft decision, JEN has established its revised capex forecasts to comply with the capex objectives specified in the Rules by:

- using demand forecasts provided by an independent expert, which addresses concerns raised by the AER in its draft decision
- assessing the sufficiency of its current compliance with regulatory obligations to identify required investments for corrective actions in a steady state
- identifying any new or changed obligations that will affect its network capital program
- examining the condition and age of its network assets
- assessing foreseeable changes in the network operating environment such as extreme weather conditions (see section 8.7.3) and the additional network performance information available through AMI to identify any additional investments required to maintain reliability
- conducting further assessment and analysis of the projects and programs identified through its planning processes
- quantifying customer initiated capital requirements as informed by independent expert demand forecasts
- incorporating escalation for expert determined input cost escalation.

Table 8-10 demonstrates how JEN's revised capex forecasts comply with the capex objectives in clause 6.5.7(a).

Table 8-10: Compliance of JEN's revised capex forecasts with the Rules

Capex objective	Rule	JEN actions to ensure compliance
Meet or manage the expected demand for standard control services	6.5.7(a)(1)	JEN has revised its demand forecasts to better align with the AER's estimates of future demand and customer numbers. This is discussed in detail in section 5.
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.7(a)(2)	JEN has assessed its current compliance as well as assessing corrective actions and additional new obligations. The projects derived in response to this assessment are described in section 8.8, with accompanying business cases and strategic planning papers in Appendices 8.10 to 8.38.
Maintain the quality, reliability and security of supply of standard control services	6.5.7(a)(3)	JEN's capex forecasts consider the impacts of ageing infrastructure, increasing utilisation on the quality, reliability and security of supply, and the impact of extreme weather conditions. JEN has proposed projects which are designed to mitigate declining reliability of its services caused by increased asset utilisation. The key projects are discussed in sections 8.6 to 8.11.
Maintain the reliability, safety and security of a distribution system through the standard control services	6.5.7(a)(4)	JEN's capex forecasts consider the impacts of ageing infrastructure, increasing utilisation on the reliability, safety and security of the distribution system and the impact of extreme weather conditions. Additional considerations, including trends of asset failures and customer reports of safety issues as they impact potential future network safety issues, have also been factored into JEN's revised capex forecasts (see supporting business cases and strategic planning papers in Appendices 8.10 to 8.38.

8.16.3 Capex criteria

Independent verification of capital program prudence for network and non-network capital

JEN obtained independent expert reviews of its original proposed capital programs (see Appendix 7.7 of original regulatory proposal). In section 8.8.4 of its original regulatory proposal, JEN set out the nature and outcomes of the review which concluded that JEN's capex, with one minor IT exception, is compliant with the prudence and efficiency capital expenditure criteria of the Rules.

Response to issues raised in the AER's draft decision

The AER, based on advice from its consultant Nuttall, generally rejected the forecasts proposed by JEN it is original regulatory proposal on the basis that it was not satisfied as to the methodology used by JEN to derive these forecasts. In particular, it expressed concern in relation to the reliance on engineering judgement, rather than economic analysis, and questioned the likelihood of JEN actually delivering the relevant projects and programs.

While JEN had undertaken a detailed planning process through its NAMP and IT Plan, and associated documentation, JEN has responded to the issues raised in the AER's draft decision by undertaking significant additional work to further develop and refine its capex forecasts.

This work has been described in detail in the preceding sections of this chapter, in particular sections 8.6 and 8.7. As a result of this work, JEN has optimised some of the projects and programs that were included in its original regulatory proposal. JEN believes that the additional documentation prepared and submitted with this revised regulatory proposal demonstrates:

- a robust analysis of those projects and programs
- explains the need for JEN to undertake the project or program in order to meet the requirements of a prudent operator of the network in JEN's circumstances
- addresses the alternative options for meeting those requirements in each case to select the most cost efficient approach.

Forecasts reflect realistic expectations of demand and input costs

JEN has relied upon suitably qualified experts to inform its capital program costs including:

- NIEIR for demand (customer numbers, energy and maximum demand) with NIEIR's revised forecasts addressing a number of the AER's concerns, such as revised economic growth and population assumptions, delaying the impact of the CPRS and recognising the termination of the home insulation scheme. NIEIR has also revised a number of policy impacts assumed in its original forecasts to incorporate better or more recent information.NIEIR's forecasts have been peer-reviewed and found to be reasonable.

- SKM, BIS Shrapnel and KPMG Econtech for estimates of material and labour cost escation. SKM have updated their real material escaltors, and have specifically incorporated a number of requirements of the draft decision. These include using the AER's foreign exchange forecasts, and making no allowances for carbon, wood poles or a trade-weighted index. The labour cost escalators from BIS Shrapnel and KPMG Econtech refelect the latest available information, which was the AER's preference in the draft decision.

8.16.4 Capex factors

The Rules set out the capex factors which the AER must have regard to when deciding whether or not to approve JEN's revised capex forecast. Table 8-11 summarises points JEN considers relevant to these factors.

Table 8-11: Capex factors

Capex objective	Rule	JEN comments
the information included in or accompanying the building block proposal	6.5.7(e)(1)	JEN has provided a comprehensive original and revised regulatory proposals supported by extensive appendices, financial models and RIN templates as well as an extensive initial response to the draft decision. JEN has provided further updated and developed information with this revised proposal to address issues raised by the AER in its draft decision.
submissions received in the course of consulting on the building block proposal	6.5.76(e)(2)	
analysis undertaken by or for the AER and published before the distribution determination is made in its final form	6.5.7(e)(3)	

Capex objective	Rule	JEN comments
benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period	6.5.7(e)(4)	JEN has provided independent benchmarking analysis from Gutteridge Haskins and Davey and Ernst & Young in Appendices 7.6 and 7.7 of its original regulatory proposal. JEN notes that Appendix F of the Nuttal report to the AER includes benchmarking analysis which shows that JEN is at or better than the efficient level for the measures selected.
the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods	6.5.7(e)(5)	JEN has provided its actual historic expenditure to the AER for 2001-2009. As discussed in earlier sections of this chapter, JEN is concerned in relation to the reliance that appears to have been placed on historic costs by the AER and its consultant, and requests that due consideration be given to thee other capex factors, in particular, the information provided by JEN.
the relative prices of operating and capital inputs	6.5.7(e)(6)	JEN relies on lifecycle management planning for each asset, which considers all strategies and options over the entire asset life from planning to disposal to deliver the lowest long-term cost. Lifecycle management focuses on ensuring effectiveness and efficiency in maintenance (opex) and replacement (capex) of the network assets based on reliability centred maintenance analysis and considers issues of safety, cost, risk and reliability (see, for example, IT scale escalator in section 7.3.5 and section 3.4.4 of NAMP included as Appendix 9.1 of JEN's original regulatory proposal). Additionally, JEN has relied upon the same input cost escalators for capex and opex.

Capex objective	Rule	JEN comments
the substitution possibilities between operating and capital expenditure	6.5.7(e)(7)	JEN has assessed these opportunities and has proposed: an enhanced asset inspection program (opex) to complement the asset replacement strategy (capex) several IT capex projects that provide for corresponding savings in IT opex costs over the forecast period. Details of these programs have been provided as part of JEN's original regulatory proposal and updated in this revised proposal.
whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period	6.5.7(e)(8)	All significant proposals to commit funds are subject to an economic evaluation. All realistic options are included in the analysis. All costs, savings (both capital and operation/maintenance) and revenues relevant to each option are included in evaluations. These revenues include an assessment of the impact of the STPIS (see individual business cases and strategic planning papers in Appendices 8.10 to 8.38).
the extent the forecast of required capital expenditure of the Distribution Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms	6.5.7(e)(9)	As discussed in Appendix 17.1 of JEN's original regulatory proposal and Appendix 6.12, JEN has established outsourcing arrangements that reflect prudent commercial terms.

Capex objective	Rule	JEN comments
the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives	6.5.7(e)(10)	JEN considers non-network alternatives in its planning process through the development of its strategic plans. There are seven embedded generators inter-connected to the network – Somerton Power Station in Somerton, Brooklyn Landfill in Brooklyn, Bolinda Landfill in Broadmeadows, Austin Hospital in Heidelberg, LaTrobe University in Preston, Mini Hydro in Preston and Australian Paper in Fairfield. In forecasting peak demand for zone substations with embedded generation, it is assumed that the generators are running at peak load periods unless otherwise specified. JEN publishes opportunities for non-network solutions in its annual planning reports and invites non-network solution proponents to contact JEN. These documents are published in order to provide transparency and information to the wider energy industry, with a specific objective of seeking opportunity for non-network solutions to defer the need for network investment.

9 Opening asset base

- JEN believes that its proposed escalation of its 2006 opening RAB is correct.
- JEN has rolled forward its asset base consistent with the AER's preferred methodology.
- As a result, the combined total capital base at 1 January 2011 is now $766.2 million ($nominal) and forecast to be $1,224.4 million ($nominal) at 31 December 2015.

9.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN established its regulatory asset base (**RAB**) as at 1 January 2011 in accordance with the requirements of Schedule 6.2.1 of the Rules by applying the RAB roll-forward method specified in the roll forward model which JEN provided to the AER on 17 November 2009 in lieu of the AER publishing a roll forward model that complies with the transitional provisions of the Rules.[287]

JEN determined that its RAB as at 1 January 2011 is $755.6 million and is forecast to be $1,098.6 million (or $1,241.4 million nominal$) at 31 December 2015, as shown in Table 9-1. Assets in JEN's RAB are used for the purpose of providing standard control services.

Table 9-1: Forecast RAB JEN's original regulatory proposal

Item	2011	2012	2013	2014	2015
Opening RAB 1 January	766.2	839.3	917.0	975.5	1,021.9
Forecast capital expenditure/ additions	126.1	139.7	126.5	120.1	131.2
Customer contributions	7.4	7.4	8.4	8.2	8.8
Disposals	0.1	2.2	0.1	0.1	0.1
Depreciation	45.5	52.3	59.5	65.4	65.7
Closing RAB 31 December	**839.3**	**917.0**	**975.5**	**1,021.9**	**1,078.5**

Note: forecast capital expenditure includes a half year of real vanilla WACC, in accordance with the PTRM.

[287] JEN notes the AER's acknowledgement that the AER's roll forward model in the form published under clause 6.5.1 of the Rules is not fit for Victorian DNSP's purposes. It is not poss ble for JEN to use the roll forward model and also comply with the substantive requirements of the Rules as they apply to Victorian DNSPs. JEN considers that its amended roll forward model complies with all relevant requirements of the Rules and, except as necessary to meet these requirements, is otherwise consistent with the AER's published roll forward model.

JEN developed its forecast customer contributions by applying the proportion of current customer contributions to current customer initiated capex to forecast customer initiated capex. This forecasting method means JEN's forecast contribution proportions are all within 10 per cent of the current period outcome.

However, since JEN submitted its regulatory proposal it has become aware that its forecast customer contributions are inconsistent with the requirements of Guideline 14. JEN has amended its modelling to ensure that the modelling of customer contributions and X-factors for standard control services is linked. This ensures that the capital contributions forecast put forward in this revised regulatory proposal is a better reflection of the capital contributions likely to result if JEN's regulatory proposal is accepted. Section 8.4 provides further detail on how JEN forecasts capital contributions.

9.2 Summary of AER's draft determination and decision

In its draft decision the AER established a 2010 closing RAB of $742.2 million which was $13.4 million less than the value proposed by JEN. The difference was the net effect of a number of separate adjustments. Notably, the AER proposes to disallow six months of the six and a half years' escalation that JEN considers is necessary to translate its 2006 opening RAB as specified in the Rules, to a 31 December 2010 dollar value that is consistent with the AER's PTRM. JEN does not accept the AER's proposal.

9.3 JEN's response to AER's draft determination and decision

The AER paraphrases Clause S6.2.1(c)(1) of the Rules to say that the "RAB value ($ real 2004, as at 1 January 2006) for [JEN is] as follows:

Jemena Electricity Networks (Victoria) (Jemena)—578.4 million …"[288]

In fact Clause S6.2.1(c)(1) of the Rules expresses it somewhat differently:

Jurisdiction	Distribution Network Service Provider	Regulatory Asset Base ($m)
Victoria	AGL Electricity[289]	578.4 (as at 1 January 2006 in July 2004 dollars) [290]

[288] Draft decision, p. 440.

[289] JEN was previously named AGL Electricity Limited.

[290] Clause S6.2.1(c)(1) of the Rules.

The Rules state explicitly that the $578.4 million is in July 2004 dollars, not simply "$ real 2004".

The AER responds to JEN's position in part as follows:

> The AER notes that all data in the 2006 EDPR were expressed in real 2004 dollars. The expression of data as at '1 July 2004' in the ESCV's 2006 EDPR reflects the fact that cashflows are assumed to be incurred evenly throughout the year (approximated by a mid year value assumption) and does not imply that data was literally valued as at 1 July 2004.

and

> The AER has examined the ESCVs' models and confirms that costs prior to 2004 were escalated by the annual CPI as per the control mechanism, which used a September CPI value. In other words, to maintain consistency with the lagged September CPI data used in the control mechanism, this September CPI was used to approximate middle of the year (1 July) values.[291]

In its final financial model for AGL Electricity for the 2006 EDPR, the ESCV labels real dollar values universally as "($m 1/7/2004)" in the sheets that deal with RAB (see Appendix 9.3).[292] If, as the AER contends, the ESCV's datum for real dollar values is not 1 July 2004, then what is the datum? JEN believes that the AER does not answer that question directly. However, by proposing that the 2006 opening RAB should be escalated by only six years' inflation to produce a 31 December 2010 value, the AER suggests that the ESCV's datum was in fact 31 December 2004. JEN contends that there is no evidence for that. On the contrary, the ESCV's labelling of real values in its financial model and the terms of clause S6.2.1(c)(1) of the Rules are consistent: the datum is 1 July 2004.

The closing statement in the passage quoted above that "this September CPI was used to approximate middle of the year (1 July) values" also supports JEN's contention that the ESCV's values are in mid year (July) dollars. In JEN's view, the fact that the ESCV used September CPI values as the basis for annual escalation does not allow or support any inference about the point in the year at which the dollar values are expressed.

Irrespective of what the ESCV did, and how what it did might be interpreted, S6.2.1(c)(1) of the Rules is unambiguous: the 2006 opening RAB of $578.4 million is expressed in July 2004 dollars. It follows that six and a half years' CPI escalation must be applied to that value to convert it to an end of year (31

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291 Draft decision, p. 448.

292 See for example cells A5, A7, A12, and A16 in the 'RAB OAV' sheet and cells A5, A12, A23, A36, A47, and A55 in the 'Assetbase' sheet.

December) 2010 value that is consistent with the structure of the AER's PTRM (see Appendix 18.1).

The AER also suggests that the additional half years' inflation proposed by JEN would "[create] an inconsistency between inflation as applied in the roll forward and in the AER's PTRM" where "the annual CPI adjustment is also approximated by September inflation." [293]

In JEN's view there is no inconsistency. Once the value of the RAB is established as at 31 December 2010, September inflation can be used for subsequent escalation of that December value. September inflation as used in that context is simply a proxy for December inflation and its use says nothing about, and does not alter, the point in the year at which the dollar values are expressed. Applying one years' inflation to an amount in dollars of one year (say 2010) simply takes that value to dollars at the same point in the next year (2011). However, if September inflation is used to escalate amounts expressed in 31 December dollars, the resultant values will only approximate the correct December values. This is illustrated by the following example which compares the results of escalating $100 in 1 July 2004 dollars by September inflation and June inflation:

Table 9-2: Inflation escalation worked example

Quarter ending	Eight capital cities Consumer Price Index (ABS)	Year on year percentage change in CPI	$100 in 1 July 2004 dollars escalated on the basis of September quarter CPI	Index value implicit in escalation based on September quarter CPI	$100 in 1 July 2004 dollars escalated on the basis of June quarter CPI
Jun-2003	141.3	2.69%			
Sep-2003	142.1	2.60%			
Jun-2004	144.8	2.48%	100.00	144.8	100
Sep-2004	145.4	2.32%			
Jun-2005	148.4	2.49%	102.60	148.56	102.49
Sep-2005	149.8	3.03%			
Jun-2006	154.3	3.98%	104.98	152.01	106.56
Sep-2006	155.7	3.94%			
Jun-2007	157.5	2.07%	108.16	156.61	108.77
Sep-2007	158.6	1.86%			
Jun-2008	164.6	4.51%	112.42	162.78	113.67

293 Draft decision, p. 448.

Quarter ending	Eight capital cities Consumer Price Index (ABS)	Year on year percentage change in CPI	$100 in 1 July 2004 dollars escalated on the basis of September quarter CPI	Index value implicit in escalation based on September quarter CPI	$100 in 1 July 2004 dollars escalated on the basis of June quarter CPI
Sep-2008	166.5	4.98%			
Jun-2009	167.0	1.46%	114.51	165.81	115.33
Sep-2009	168.6	1.26%			
Jun-2010	171.3[294]	2.57%	120.22	174.07	118.30

Applying September inflation to the July 2004 dollar value results in escalated July values that are sometimes greater than and sometimes less than the "correct" value that would be obtained by applying June inflation. If a true 1 July value is required at some time in future then it will be necessary to make an adjustment for the difference between the CPI number implicit in the September inflation series as applied from July 2004 and the actual June CPI number as published by the Australian Bureau of Statistics.

The example above also illustrates why it is necessary to escalate an amount expressed in 1 July 2004 dollars by six and a half years' inflation to produce an amount in 31 December 2010 dollars. If only six years' inflation is applied - whether on a September or June basis - the result is an amount in 1 July 2010 dollars.

9.4 JEN's revised regulatory proposal

Following its review of the AER's draft decision, JEN has believes that the AER is incorrect in rejecting JEN's proposed escalation of its 2006 opening RAB. Therefore, JEN has retained its proposed capital base roll-forward calculation with updates to reflect its revised net capex forecast and inflation set out in this revised regulatory proposal.

Table 9-3 shows JEN's adjusted 2010 and 2015 closing capital base values compared with corresponding values from JEN's original regulatory proposal and the AER's draft decision.

294 Estimated value.

Table 9-3: Comparison of capital base values ($nominal)

Item	Closing 2010	Closing 2015
JEN November 2009 proposal	755.6	1,241.4
AER draft decision	742.2	927.9
JEN adjusted regulatory proposal	766.2	1,224.4

10 Depreciation

- JEN accepts the AER's draft decision in relation to depreciation in principle.
- JEN notes that asset category standard lives for the 2011-2015 period must be recalculated to be consistent with the weightings of expenditure on the asset types in each category as finally decided.

10.1 Summary of JEN's original regulatory proposal

JEN adopted a straight line depreciation method (on an inflation-adjusted asset base) for the forthcoming regulatory control period. JEN has used this depreciation method in the current and previous regulatory control periods. It is also the default method adopted by the AER for the PTRM.

JEN considered that a straight line depreciation method is consistent with clause 6.5.5(b)(i) of the Rules across all asset classes.

JEN adopted the same asset classes as prescribed by the ESCV.

For each asset category, the standard life is the weighted average of the standard lives of the asset classes in that category, where the class lives are those JEN uses for engineering design purposes.

Table 10-1 shows JEN's forecast regulatory depreciation in its original regulatory proposal over the forthcoming regulatory control period.

Table 10-1: Forecast regulatory depreciation (original regulatory proposal)

Details, 2010 $m	2011	2012	2013	2014	2015	Total
Straight line depreciation	45.9	53.0	60.1	60.8	59.8	279.8
Inflation on opening RAB	18.2	20.3	22.3	23.9	25.2	109.9
Regulatory depreciation	**27.7**	**32.7**	**37.9**	**36.9**	**34.7**	**169.9**

10.2 Summary of AER's draft determination and decision

In its draft decision the AER:

- accepted the establishment of a new asset category for equity raising costs[295]

[295] Draft decision, p. 464.

- accepted JEN's proposed standard asset lives for capex over the forthcoming regulatory control period[296]

- requires that JEN's 2010 estimated capex be brought into the remaining life calculation using the standard lives approved by the ESCV for the current regulatory period rather than at the average of the ESCV's standard lives and the standard lives proposed by JEN (and accepted by AER) for the forthcoming regulatory control period.[297]

10.3 JEN's response to AER's draft determination and decision

10.3.1 Standard lives for capex over the next regulatory control period

The standard life proposed (and accepted) for each asset category[298] is an average of lives of a range of different asset types. The average life for a particular asset category is a function of the relative weightings of expenditure on the asset types in the category.

JEN expects that the AER will recalculate the standard lives of all asset categories to reflect its final determination on capital expenditure. The clearest example of this is in the non-network general assets-other category which includes JEN's proposed expenditure on merging and relocating the Broadmeadows and Sunshine depots. If the AER was to follow through with its draft decision and disallow that expenditure then the significant expenditure on buildings (with a 50 year life) must be removed from the calculation of standard life for that category.

10.3.2 Remaining lives for 2010 capex

JEN has incorporated the AER's position.

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296 Draft decision, p. 465.

297 AER, op.cit., pp. 465-6.

298 AER, op.cit.., Table 10.4.

10.4 JEN's revised regulatory proposal

Table 10-2 shows JEN's revised forecast regulatory depreciation over the forthcoming regulatory control period.

Table 10-2: Revised forecast regulatory depreciation

Details, 2010 $m	2011	2012	2013	2014	2015	Total
Straight line depreciation	45.50	52.29	59.54	65.42	65.69	288.43
Inflation on opening RAB	19.20	21.03	22.98	24.45	25.61	113.27
Regulatory depreciation	26.30	31.25	36.56	40.97	40.08	175.17

11 Cost of Capital

- JEN proposes a nominal vanilla weighted average cost of capital (**WACC**) of 10.29 per cent.
- JEN's cost of capital calculation incorporates a number of aspects of the AER's draft decision (without necessarily agreeing with the correctness of the AER's position or the reasons given by the AER for its position), including a revised market risk premium of 6.5 per cent and an updated inflation forecast of 2.57 per cent. JEN continues to use a gearing ratio of 0.60, consistent with the SORI and the AER's draft decision.
- JEN has updated its estimate of the risk-free rate to 5.65 per cent using JEN's averaging period of 19 April 2010 to 31 May 2010.
- JEN proposes a debt risk premium (**DRP**) estimate of 4.28 per cent using the averaging period described above and an updated methodology proposed by PwC and CEG. JEN has serious concerns with the methodology used by the AER in its draft decision and has submitted expert reports from PwC and CEG on the matter.

11.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN assessed the prevailing market conditions affecting its cost of capital. This assessment was undertaken with due regard to the relevant requirements of the Rules, the RIN, the AER's Statement of Regulatory Intent on the WACC (**SORI**)[299], the AER's final decision on the WACC[300] and well accepted methods for estimating the cost of capital for assets with JEN's risk profile. In particular, JEN proposed a method recommended by PwC to estimate the debt risk premium (**DRP**) for a benchmark efficient electricity network.[301]

JEN proposed a nominal vanilla WACC of 10.86 per cent calculated in accordance with clause 6.5.2 of the Rules. JEN estimated its cost of equity component of WACC using the (**CAPM**) as required by clause 6.5.2(b).

299 AER, *Electricity Transmission and Distribution Network Service Providers Statement of Regulatory Intent on the Revised WACC Parameters (Distribution)*, May 2009.

300 AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Final Decision*, May 2009.

301 PwC, *Victorian Distribution Businesses, Methodology to Estimate the Debt Risk Premium,* November 2009. See Appendix 11.10.

JEN considered that its proposed cost of capital appropriately reflected the return required by investors in a commercial enterprise facing similar risks to JEN, as required by clause 6.5.2(b) of the Rules.

Table 11-1 summarises JEN's proposed WACC parameters (based on a proxy averaging period) and resulting WACC variants as provided in its original regulatory proposal.

Table 11-1: JEN's proposed WACC Parameters from original regulatory proposal

Parameters	JEN proposal
Inflation (i)	2.47%
Nominal risk-free rate (R_f^n)	5.47%
Real risk-free rate	2.93%
Debt margin (D^n)	4.71%
Nominal pre-tax cost of debt	10.18%
Real pre-tax cost of debt	7.52%
Market risk premium (MRP^n)	8.0%
Equity beta (β_e)	0.80
Post-tax nominal return on equity	11.87%
Gearing (D/V)	60%
Dividend imputation (γ)	0.20
Corporate tax rate (T_c)	30%
Nominal vanilla WACC	10.86%
Real vanilla WACC	8.18%

Notes:

1. Real costs of debt and equity and the risk-free rate are calculated from the nominal equivalents using the Fisher equation and forecast inflation.

11.2 Summary of AER's draft determination and decision

The AER draft determination estimated a nominal vanilla WACC of 9.68 per cent for JEN, determined using a proxy averaging period of 1 March 2010 to 19 March. This was 1.18 percentage points less than that proposed by JEN in its November 2009 regulatory proposal. The primary reason for the difference is the values used by the AER for the market risk premium and debt risk premium. The AER also updated the risk free rate and foreshadowed further changes to the risk free rate, debt risk premium and expected inflation rate closer to its final determination.[302]

In making its draft decision the AER has not accepted JEN's submission on market risk premium as persuasive evidence justifying a departure from the value set out in the SORI.[303]

Table 11-2 compares the parameter values and WACC proposed by JEN[304], with corresponding values in the AER's SORI[305] and draft decision[306]:

Table 11-2: Comparison of WACC parameters and values

Parameters	JEN's original proposal	SORI	AER draft decision
Inflation (i)	2.47%	N/A	2.57%
Nominal risk-free rate (R_f^n)	5.47%	10 year CGS	5.66%
Debt margin (D^n)	4.71%	N/A	3.25%
Credit rating	BBB+	BBB+	BBB+
Nominal pre-tax cost of debt	10.18%		8.90%
Market risk premium (MRP^n)	8.00%	6.50%	6.50%
Equity beta (β_e)	0.80	0.80	0.80
Nominal post-tax cost of debt	11.87%	N/A	10.85%
Gearing (D/V)	60%	60%	60%
Dividend imputation (γ)	0.20	0.65	0.65
Nominal vanilla WACC	10.86%	N/A	9.68%

The AER draft decision considered imputation credits (gamma) in chapter 12. JEN has adopted this approach for the purposes of this section on cost of capital and discusses gamma in chapter 12.

[302] AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, p. XLI.

[303] AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, p. 503.

[304] JEN, *Regulatory Proposal 2011-15*, November 2009, Table 12-3.

[305] AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, Table 24.

[306] AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, Table 25.

11.3 JEN response to AER's draft determination and decision

Table 11-3 summarises JEN's responses to the AER's draft determination and decision.

Table 11-3: JEN's responses to the AER's draft decision – cost of capital

Change	Related AER amendments	JEN incorporation	Summary of explanation	Explanation in this document
Risk-free rate	5.1, 5.2	Incorporated	Updated for JEN averaging period	Section 11.4
Equity beta	5.1, 5.2	Incorporated	Use equity beta of 0.80	Section 11.5
Market risk premium	5.1, 5.2	Incorporated	Use market risk premium of 6.5 per cent	Section 11.6
Gearing	5.1, 5.2	Incorporated	Use gearing ratio of 0.60	Section 11.7
Debt risk premium	5.1, 5.2	Has not incorporated	Use debt risk premium of 4.28 per cent	Section 11.8
Inflation forecast	5.1, 5.2	Incorporated	Use inflation forecast of 2.57 per cent	Section 11.9

JEN provides detail on its response to the AER's draft decision below.

11.4 Risk-free rate

JEN proposes a nominal risk free-rate of 5.65 per cent by applying the method adopted by the AER in its draft decision.

The method was originally proposed by JEN in its November 2009 regulatory proposal and subsequently accepted by the AER. It uses the 30 business day historical average of the annualised yield on 10 year Commonwealth Government Securities (**CGS**) from 19 April 2010 to 31 May 2010 (**the JEN averaging period**).[307][308] These yields are sourced from the indicative mid rates published by the RBA.[309]

307 The JEN averaging period was proposed by JEN in its November 2009 regulatory proposal and subsequently accepted by the AER.

See Jemena Electricity Networks (VIC) Ltd, 30 November 2009, *Regulatory Proposal 2011–15,* p.

JEN estimates this yield on a 10 year CGS maturing at the 30 business days to 31 May 2020 by interpolating on a straight-line basis the yields on the CGS bonds maturing at 15 April 2020 and 15 May 2021. JEN applies this method in its WACC model (see Appendix 11.9).

11.5 Equity beta

JEN proposed an equity beta of 0.80 in its original proposal, and the AER accepted this value in its draft decision. JEN has not revised its proposed equity beta.

JEN considers that an equity beta of 0.80 reflects the minimum sustainable measure of systematic risk for an efficient electricity business.

11.6 Market risk premium

In this revised proposal, JEN has incorporated the AER's market risk premium (**MRP**) estimate of 6.5 per cent. But, in doing so, JEN does not necessarily accept the correctness of this MRP or the AER's reasons for adopting it.

JEN maintains its view that forward-looking estimates suggest an MRP higher than 6.5 per cent, particularly given the continued uncertainty surrounding the current financial and economic crises.

The AER maintains that the value of 6.5 per cent for the MRP in the SORI reflected market conditions during the global financial crisis.[310] However, as per its original proposal, JEN considers that 8 per cent is a better estimate of the MRP given current market conditions.

This view is shared by Professor Bob Officer and Dr Steven Bishop in a recent report:[311]

> We reinforce our view that a MRP of 8% for the 2011 to 2015 regulatory period reflects current circumstances and a view as to what will prevail over the regulatory period.

This report also responds to a number of matters raised in the AER's draft decision, see Appendix 11.12. Appendix 11.12 refers to an earlier report by Professor Bob Officer and Dr Steven Bishop, see Appendix 11.13.

See AER, 8 January 2010, *Letter: Victorian 2011-15 electricity distribution determination – approval of proposed risk free rate averaging period*.

308 JEN also uses this period to estimate the debt risk premium (see section 11.8).

309 See http://www.rba.gov.au/statistics/tables/xls/f16.xls.

310 AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, p. 492.

311 Professor Bob Officer and Dr Steven Bishop, July 2010, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, p. 2.

11.7 Gearing ratio

JEN incorporates the AER's gearing ratio of 0.60.

JEN considers that a gearing ratio of 0.60 is efficient for a stand-alone electricity distribution business and is consistent with JEN's proposed cost of equity and debt risk premium estimates above.

11.8 Debt risk premium

JEN proposes a debt risk premium (**DRP**) of 4.28 per cent for a BBB+ rated benchmark efficient service provider. This premium is added to the nominal risk-free rate estimate of 5.65 per cent to give JEN's proposed cost of debt of 9.93 per cent. JEN has not incorporated the method and assumptions used by the AER to estimate the DRP in its draft decision.

In light of the ongoing regulatory debate and uncertainty around the measurement of the DRP, JEN welcomes the AER's observation that "it will consider further refinements to its approach in setting the DRP in the future".[312] JEN considers that the AER's current approach to estimating the DRP, as set out in its draft decision, is flawed in a number of respects, and results in a DRP estimate which does not properly reflect the nature and degree of risks faced by distribution businesses.

JEN's proposed DRP is a function of two key factors:

- *Credit rating*—JEN uses a BBB+ credit rating, consistent with the SORI and the AER's draft decision
- *Method for calculating DRP based on credit rating*—JEN proposes a different method to the AER for estimating the DRP based on the BBB+ credit rating. JEN's method is described by PwC in more detail in Appendix 11.6 and is supported by reports from CEG in Appendices 11.2 and 11.3.

The rest of this section discusses the AER and JEN methods for calculating DRP in more detail and is laid out as follows:

- the Rules and the SORI require an estimate of the DRP for BBB+ rated 10 year fixed rate Australian corporate bonds
- the AER's method for estimating the DRP
- the AER has not satisfied the requirements of the Rules because of material errors with both the AER's method of estimating DRP and its application

[312] Draft decision, p. 515.

- JEN's method for estimating the DRP
- JEN's method corrects for the errors in the AER's method
- JEN's method results in a DRP estimate of 4.28 per cent.

11.8.1 Requirement of the Rules and the SORI–an estimate of the DRP for BBB+ rated 10 year Australian corporate bonds

The Rules require the cost of debt component of JEN's rate of return to reflect the return on debt that would be required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by JEN.[313]

Clause 6.5.2(b) requires the cost of debt to be calculated as:

> $k_d = r_f + DRP$
>
> Where:
>
> r_f = the nominal risk-free rate
>
> DRP = the debt risk premium for the regulatory control period determined in accordance with clause 6.5.2(e).

Clause 6.5.2(e) defines the DRP as:

> the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency.

The AER's SORI requires that the DRP be calculated by reference to bonds with: [314]

- a 10 year maturity, and
- a BBB+ credit rating.

Based on the above, JEN considers that the question to be answered when assessing the DRP in a regulatory proposal is: "what is the best estimate of the DRP for 10 year BBB+ rated Australian corporate bonds?"

JEN considers that the AER's draft decision does not adequately answer this question in assessing the DRP in JEN's regulatory proposal. JEN considers that

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[313] NER, clause 6.5.2.

[314] AER, May 2009, *Electricity Transmission and Distribution Network Service Providers Statement of Regulatory Intent on the Revised WACC Parameters (Distribution)*.

its method provides a more accurate estimate of the DRP for 10 year BBB+ Australian corporate bonds.

11.8.2 The AER's method for estimating the DRP

In its draft decision, the AER found that CBASpectrum's BBB+ fair value curve results in the best available prediction and used this curve to estimate a DRP of 3.25 per cent for a 10 year BBB+ corporate bond over the 15 business days to 19 March 2010.[315] The AER considered that this estimate met the need for the return on debt to reflect the current cost of borrowings for comparable debt.[316]

To support this finding, the AER applied the following three step method (**the AER method**) to choose between the Bloomberg and CBASpectrum services:[317]

- *step one:* source yield estimates for a sample of BBB+ rated bonds that meet certain criteria
- *step two:* test the accuracy of the respective fair value curves in predicting the yields on those bonds
- *step three:* choose the most accurate fair value curve as the basis for determining the observed annualised Australian benchmark rate for corporate bonds with a BBB+ credit rating and a maturity of 10 years.

However, as CEG point out, the draft decision does not provide a clear explanation of the how the AER selected its sample under step one.[318] Further, as PwC note, the AER's approach to testing the accuracy of the respective fair value curves (step two) appears to be methodologically flawed.[319]

11.8.3 The AER has not satisfied the requirements of the NER

Expert reports by PwC and CEG both demonstrate that there are material errors with both the AER's method for determining the DRP and how the AER applied its stated method.[320] Based on this expert evidence, JEN considers that the AER's

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315 Draft decision, p. 523.

316 Draft decision, p. 523.

317 Draft decision, pp. 514–523.

318 CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, p. 16. See Appendix 11.2.

319 PricewaterhouseCoopers, 19] July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 5-7. See Appendix 11.6.

320 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia. See Appendix 11.6.

CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs. See Appendix 11.2.

method is not fit for purpose and fails to satisfy the requirements of the NER. The AER's method results in an estimate of the DRP which does not appropriately reflect the nature and degree of risk faced by distribution businesses.

After reviewing the AER's draft decision, PwC conclude that AER's analysis suffers from a number of important errors.[321] Similarly, CEG conclude that:[322]

> the methodology set out in the Draft Decision fails to result in the most accurate estimate of the [cost of debt as required by the NER]. That is, the methodology in the Draft Decision does not, and will not, deliver a [cost debt as required by the NER] that, when put into the [WACC] formula, will provide a service provider with a rate of return equivalent to that is required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business of the provider. The AER's methodology does not provide a forward-looking rate of return that is commensurate with prevailing conditions in the market for funds and the risks involved in providing standard control services.

PwC and CEG identify at least four errors:[323] two relate to the AER's method itself:

- 1. the method does not test whether the CBASpectrum or Bloomberg fair value curves are biased.
- 2. the method does not assess the extrapolation implicit in the CBASpectrum BBB+ fair value curve.

The other two errors relate to how the AER applied its stated method:

- 3. the AER incorrectly excluded the DBCT bond from its sample of bonds, resulting in the incorrect choice of CBASpectrum data over Bloomberg data.
- 4. the AER ignored information from a wider range of sources, such as yields on floating rate BBB+ rated bonds and fixed rate bonds in the A- and BBB credit bands.

Each error is explained further below.

CEG, July 2010, *Detailed application of AER cost of debt methodology to alternative bond samples*. See Appendix 11.3.

These reports are supported by Appendices 11.4 to 11.5 and 11.7 to 11.11.

321 PricewaterhouseCoopers, 19 July 2010*, Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 5–7. See Appendix 11.6.

322 CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, p. 1. See Appendix 11.2.

323 PricewaterhouseCoopers, 19 July 2010*, Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 5–7. See Appendix 11.6;

The AER's method does not test whether the CBASpectrum or Bloomberg fair value curves are biased

The AER method does not involve any testing for bias in the CBASpectrum or Bloomberg fair value curves. By ignoring potential bias issues, the AER method does not test whether these curves systematically under- or over-estimate the underlying data. This is an error. [324]

Here, there are two tests to consider:[325]

- *the weighted sum of squared errors test*—examines the accuracy, or goodness of fit, of the relevant fair value curve relative to the underlying source data, such as CBASpectrum, Bloomberg or UBS, and is the test used by the AER
- *the average error test*—measures whether, across a sample of bonds, the relevant fair value curve systematically under- or over-states the observed DRP and is the test that was previously preferred by regulators.

These tests are explained further in Appendix 11.7.

PwC explain why the second test is so important and why the AER's method is incomplete without it:[326]

> The AER's weighted sum of squared errors test does not allow it to test whether the service that provides a return that is commensurate with current conditions in the market, or reflects the current cost of borrowing. If it finds that a service provides a marginally better 'fit' to the yield data, it cannot say whether the service provides a return that is commensurate with current conditions in the market for funds. If the service is found to understate the returns required in the market, but provides a closer 'fit' under the AER's test, it will be adopted by the AER even though it under-states the current cost of borrowing, it cannot provide a return that recovers at least the efficient costs of operation, and is therefore not compliant with the requirements of the NER.

Any method used to estimate a DRP by selecting between fair value curves should that resulting estimates are unbiased.[327] Ignoring any potential bias may result in the selection of a curve which systematically under- or over-states yields and

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324 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 14. See Appendix 11.6.

325 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 14. See Appendix 11.6.

326 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 14–15. See Appendix 11.6.

327 See, for instance, CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, p. 18. See Appendix 11.2.

therefore produces a DRP estimate which does not reflect the risks faced by the business, as required by the NER.

This is of particular concern for the CBASpectrum fair value curves, given that PwC notes that "CBASpectrum considers its curves to be long run averages, rather than necessarily being reflective of 'prevailing conditions' in the market for funds".[328] If these curves are not commensurate with prevailing market conditions, then it is extremely important to test whether they are systematically biased.

The AER's method does not assess the extrapolation implicit in the CBASpectrum BBB+ fair value curve

As noted above, the key question is: "what is the best estimate of the DRP for a 10 year BBB+ rated Australian corporate bond?" Thus, any method for estimating this DRP should directly test the accuracy of the 10 year estimate. But the AER method does not do this.

Rather, after selecting the CBASpectrum BBB+ fair value curve by testing it against bonds with a maximum maturity of 5 years, the AER adopts CBASpectrum's estimate of the fair value yield on 10 year BBB+ rated corporate bonds without question. Hence, the AER ignores the extrapolation that is implicit in this curve to get from 5 years out to 10 years. Further, after selecting this curve, the AER states that:[329]

> the issue of extrapolation does not affect the value of the DRP determined here.

JEN considers this is wrong and so does PwC:[330]

> At best, the AER has only tested the respective fair value curves up to a term of 5 years (the longest dated bond if the DBCT bond is excluded). It has merely assumed that the debt risk premiums predicted by the CBASpectrum service beyond this point are also 'accurate'. However, the AER has acknowledged that it does not know how the CBASpectrum service predicts yields for bonds at terms that are beyond its input data (due to their proprietary nature, many aspects of the CBASpectrum and Bloomberg methodologies are not known). It is highly inappropriate, therefore, merely to assume that CBASpectrum's extrapolation method is correct. In addition, the AER has not tested whether the increase in the debt risk premium between 5 and 10 years predicted by CBASpectrum is reasonable against other evidence.

CEG supports this position: [331]

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[328] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 24. See Appendix 11.6.

[329] Draft decision, p. 520.

[330] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 6. See Appendix 11.6.

[331] CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, p. 1. See Appendix 11.2.

> In our view, this involves an important error in that the AER methodology is not attempting to answer the correct question (the *'wrong question error'*). Specifically, the correct question is which of the fair value curves best estimates the 10 year BBB+ cost of debt. However, by applying the AER's test to the AER's sample of bond yields it has effectively asked which curve best estimates the cost of debt for maturity of around 3.6 years.

Further, it is inconsistent for the AER to scrutinise the method proposed by PwC to extrapolate the Bloomberg fair value curve to 10 years, but not the method used by CBASpectrum.[332]

JEN's proposed method, discussed below, tests the extrapolation of both the CBASpectrum and Bloomberg curves. This helps test the accuracy of any 10 year DRP estimate.

The AER incorrectly excluded the DBCT bond from its sample of bonds, resulting in the incorrect choice of CBASpectrum data over Bloomberg data

In applying its method, the AER excludes the Dalrymple Bay Coal Terminal (**DBCT**) bond from its already small sample of bonds used to test the accuracy of the fair value curves.[333] The DBCT bond is currently the longest dated BBB+ fixed rate Australian corporate bond and therefore the only bond able to inform an assessment of the fair value curves at longer maturities.

JEN considers that this was a critical error that ultimately leads to the AER incorrectly choosing the CBASpectrum BBB+ rated fair value curve over the Bloomberg BBB fair value curve.

This view is shared by both CEG and PwC. CEG identify four errors with the AER's exclusion of the DBCT bond: [334]

- incorrectly assessing whether the yield on the DBCT bond over the sample averaging period was an outlier by comparing its average yield since January 2009 with the average yields of the other bonds in the sample
- failure to use the relevant sample by only comparing the DBCT yield to the yield on the five other bonds in its initial sample and not including:
  - up to 17 comparable BBB and A- rated fixed rate bonds with similar maturities

[332] Draft decision, pp. 520–522. PwC's extrapolation method was originally proposed in its November 2009 report, see Appendix 11.10.

[333] Draft decision, pp. 518–519.

[334] CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, pp. 5–12 and 27–43. See Appendix 11.2.

– comparable floating rate bonds

- failure to adjust for the longer maturity of the DBCT bond when comparing it to the AER's sample of bonds, all of which had shorter maturities
- incorrectly using the Chow test to test for outliers, which is a test for identifying a structural break in a bond's yield or DRP, not a test of whether the bond is an outlier.

PwC also identifies further errors in the AER's method, including that it:[335]

- gave no direct evidence that the finance community considered the DBCT bond to be an outlier during the draft decision averaging period, despite evidence from Standard & Poor's rating agency that suggests otherwise
- ignored relevant data from UBS, the Royal Bank of Scotland and Bloomberg indicating that CBASpectrum's estimate of the yield on the DBCT bond was the outlier, not the DBCT bond itself.

Together, PwC's and CEG's analysis provides a clear demonstration that the AER incorrectly excluded the DBCT bond from its sample of bonds. PwC conclude:[336]

> We do not agree with the exclusion in the AER's DNSP Draft decision of the DBCT bond on grounds that is an outlier.

And further:[337]

> We consider the reasons that the AER provided in the DNSP Draft decision for the DBCT bond being an outlier are speculative and unreasonable.

As noted by CEG, excluding the DBCT bond had a critical impact on the AER's DRP estimate, contributing to the AER's erroneous conclusion that the CBASpectrum curve was the better predictor of 10 year BBB+ yields:[338]

> When some or all of the above errors are corrected, the AER methodology would unambiguously find that the Bloomberg fair value curve was the more accurate estimate of the ten year... cost of debt [required by the NER] in the relevant period of analysis.

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335 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 10–13. See Appendix 11.6.

336 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 10. See Appendix 11.6.

337 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 11. See Appendix 11.6.

338 CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, p. 11. See Appendix 11.2.

PwC draws the same conclusion:[339]

> As discussed above, we recommend including the DBCT bond in the sample of bonds that is used to test the accuracy of the fair value curves, which results in the Bloomberg curve being selected.

The AER ignored information from a wider range of sources

A fair and accurate method for estimating the DRP or cost of debt for 10 year Australian corporate debt should consider a wide range of market data, such as estimated yields on:[340]

- bonds that are covered by one or two of UBS, CBASpectrum or Bloomberg but not all three
- BBB+ floating rate bonds (once swapped into an equivalent fixed rate yield)
- bonds that do not have a BBB+ rating (such as BBB or A- rated bonds)
- bonds that are issued in Australia by foreign companies.

However, the AER's method ignores these yields and in doing so has, as CEG puts it, failed to answer the question posed by the Rules and the SORI—namely, what is the most accurate estimate of the DRP or cost of debt on a 10 year BBB+ rated fixed rate Australian corporate bond.

JEN considers that this is unjustifiable and CEG agrees:[341]

> The AER methodology's failure to have regard to this data can be termed a *non corresponding data set error*. That is, the AER fails to have regard to the most relevant information required to answer the correct question.

This view is supported by PwC:[342]

> [B]y restricting its attention only to the Bloomberg and CBASpectrum fair value curves and the limited number of BBB+ rated Australian corporate bonds on issue, the AER has ignored other potentially useful sources of information that may assist in improving the estimate of the debt risk premium that is 'commensurate with prevailing conditions in the market' for a 10 year BBB+ Australian corporate (fixed rate) bond.

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339 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 25. See Appendix 11.6.

340 CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs. See Appendix 11.2.

341 CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, p. 5. See Appendix 11.2.

342 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 6. See Appendix 11.6.

By ignoring this data, JEN considers that the AER's method is flawed. Including this data in a fair and accurate method would show that the Bloomberg fair value curve is a better predictor of the cost of debt (and therefore DRP) for bonds at longer maturities.[343]

11.8.4 JEN's method for estimating the DRP

Based on PwC and CEG advice, JEN proposes a four-step method for estimating the DRP that corrects the errors identified with the AER's method and its application (**the JEN method**).[344] The method selects between the Bloomberg BBB and CBASpectrum BBB+ fair value curves.

- *Step one: test the integrity of the curves to the extent possible*—test whether the integrity of the data and method underlying the curves is sufficiently robust to allow reliance on the results. If not, then that curve should not be used
- *Step two: test the predictive accuracy of the curves*—assess whether the fair value curves provide estimates that are statistically unbiased and represent a good fit to the yields on a sample of bonds (i.e. the data points). If a curve is biased or has a poor fit, then it should not be used
- *Step three: test the extrapolation of the curve beyond the data points*—extrapolate each curve beyond the data points to 10 years and test the reasonableness of the extrapolation:
  - for the CBASpectrum curve, use the extrapolation implicit in its CBASpectrum BBB+ fair value curve
  - for the Bloomberg curve, use the Bloomberg AAA fair value curve if available, otherwise use the last available AAA curve.[345]

  Select the most reasonable extrapolation method by comparing it to other data sources, such as:

  - the movement in DRP between zero and five years in the same curve

343 CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, p. 5. See Appendix 11.2.

PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 25. See Appendix 11.6.

344 PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 3–4.and 35 See Appendix 11.6.

345 Here, the debt margin on 10 year bonds is calculated as follows:

$$DRP(BBB)_{10yr} = DRP(BBB)_{5yr} + \left(DRP(AAA)_{10yr} - DRP(AAA)_{5yr}\right).$$

– the DRP observed in bonds of five and 10 year terms issued by a single company, such as the five and 10 year Telstra bonds

– the change in DRP observed in the Bloomberg AAA curve between five and 10 years

- *Step four: cross-check the DRP estimate against other information*—use the curve selected in step three to estimate the DRP for a 10 year BBB+ rated Australian corporate bond and compare it to other market evidence to the extent possible, such as:

  – the DRP implicit in the yields of floating rate BBB+ rated bonds (converted to a fixed rate equivalent) and bonds with other credit ratings, including fixed rate A- and BBB rated bonds

  – DRP estimates from market practitioners.

  If the estimate is not reasonable, then consider an alternative.

Step one has three tests and step two has two stages—these are described below. Appendices 11.2 to 11.11 provide further description of the PwC and CEG methodology and analysis of the AER draft decision.

Step one—three tests

Under step one, JEN proposes three tests of the Bloomberg and CBASpectrum services based on advice from PwC:[346]

- *1. Divergence in bank opinions*—does the coefficient of variation of bank feeds into Bloomberg for the Australian corporate bonds of greater than three years duration that are considered for Bloomberg's fair value curve exceed 0.05?

- *2. Divergence of fair value yield from the bank opinions*—does the average value of the difference between Bloomberg or CBASpectrum yield estimate and the mean of bank feeds for the Australian corporate bonds, expressed as a percentage of the yield, exceed ± 2.50 percent?

- *3. Divergence of fair value curve from yield estimates*—does the average value of the difference between Bloomberg's (CBASpectrum's) fair value

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[346] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 35 See Appendix 11.6.

The tests are explained in more detail in Appendices 11.8 and 11.10.

curve and the Bloomberg (CBASpectrum) bond yield estimate, expressed as a percentage of the bond yield estimate exceed ± 4.00 percent?

Step two—two stages

Under step two, JEN proposes two stages:

- *A. Select sample of bonds*—source yield estimates for a sample of BBB+ rated bonds that meet certain criteria, similar to step one of the AER's method. This sample should exclude outlier bonds, which are identified for JEN's averaging period, by:
  - considering a range of information sources, such as the opinions of credit rating agencies
  - comparing potential outliers to a relevant sample of bonds and data from other sources, such as the Royal Bank of Scotland, UBS, Bloomberg and CBASpectrum
  - not applying the Chow test, which is only relevant in identifying structural breaks
- *B. Test for accuracy and bias of curves against sample*—test the accuracy and bias of the respective fair value curves in predicting the yields on the sample of bonds:
  - *test for accuracy*, by comparing the weighted sum of squared errors associated with each curve
  - *test for bias*, by comparing the (simple) average error associated with each curve, consistent with the practice of regulators and advisors prior to the global financial crisis.[347]

11.8.5 JEN's method corrects the errors with the AER's method

JEN's method corrects the errors with the AER's method by:

- testing for both bias and accuracy of the CBASpectrum and Bloomberg curves

[347] PricewaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, p. 10. See Appendix 11.11.

PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 14. See Appendix 11.6.

- analysing the extrapolation implicit in the CBASpectrum BBB+ fair value curve, as well as the explicit extrapolation of the Bloomberg BBB fair value curve

- correctly testing for outliers by comparing a more relevant sample of bonds, not relying on the Chow test and recognising the opinions of credit rating agencies

- comparing the DRP estimate for a 10 year BBB+ rated Australian corporate bond to a wider range of data.

As a result, JEN considers that its method produces an estimate of the DRP that better satisfies the requirements of the NER.

11.8.6 JEN's method results in a DRP estimate of 4.28 per cent

Applying the JEN method to its averaging period results in a DRP estimate of 4.28 per cent for 10 year BBB+ rated Australian corporate bonds. JEN considers that this estimate is the best estimate in the circumstances and is commensurate with prevailing market conditions.

PwC applied the four-step method for JEN's averaging period and concluded that:[348]

> the Bloomberg BBB band fair value curve provides a more accurate prediction of the estimates from different providers of the yields of Australian BBB+ corporate bonds than the alternatives that the AER offers (namely the CBASpectrum BBB+ fair value curve and average of the Bloomberg BBB band and CBASpectrum curves).

PwC finds that:

- the Bloomberg BBB fair value curve passes the tests under step one, but the CBASpectrum BBB+ fair value curve does not [349]

- the DBCT bond is not an outlier, and in fact, CBASpectrum's estimate of the yield on this bond may actually be the outlier[350]

- with the DBCT bond included in the sample, the Bloomberg BBB fair value curve is more accurate and has less downward bias than the CBASpectrum BBB+ fair value curve[351]

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[348] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 2. See Appendix 11.6.

[349] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 2 and 35–36. See Appendix 11.6.

[350] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 5 and 10–13. See Appendix 11.6.

- with the DBCT bond excluded from the sample, the CBASpectrum BBB+ fair value curve systematically understates observed yields[352]

- the CBASpectrum BBB+ fair value curve gives an implausibly low extrapolation of the DRP beyond five years[353]

- extrapolating the Bloomberg BBB fair value curve using the Bloomberg AAA fair value curve gives a reasonable estimate of the DRP for 10 year BBB+ rated corporate bonds when compared to other sources, including an expert report from market practitioner Mr. Terry Toohey.[354]

Similarly, CEG finds, for JEN's averaging period, that:

- the DBCT bond is not an outlier, even if the sample of relevant bonds is restricted to only include the six bonds used by the AER in its draft decision to test whether the DBCT bond was an outlier[355]

- the information on long maturity bonds clearly supports the selection of the fair value curve that is highest at 10 years, namely, the Bloomberg BBB fair value curve.[356]

On this basis, PwC recommend using the Bloomberg BBB fair value curve and extrapolating it using the Bloomberg AAA fair value curve.[357] PwC estimate a DRP of 4.28 per cent using these Bloomberg curves as follows: [358]

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[351] PricewaterhouseCoopers, 19] July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 16–17. See Appendix 11.6.

[352] PricewaterhouseCoopers, 19] July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 17. See Appendix 11.6.

[353] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 19–22. See Appendix 11.6.

[354] PricewaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 25 and appendix D. See Appendix 11.6.

[355] CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, pp. 33–43. See Appendix 11.2.

[356] CEG, July 2010, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, a report for Victorian Electricity DBs, pp. 4–5 and 44–49. See Appendix 11.2.

CEG, July 2010, *Detailed application of AER cost of debt methodology to alternative bond samples*. See Appendix 11.3.

[357] PriceWaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, pp. 2 and 25. See Appendix 11.6.

[358] PriceWaterhouseCoopers, 19 July 2010, *Methodology for the calculation of debt risk premium – Extension*, Letter to CitiPower and Powercor Australia, p. 31. See Appendix 11.6.

Table 11-4: JEN’s proposed debt premium (per cent)

Fair value curve	Calculation	Bloomberg yield	CGS yield (RBA)	DRP (Bloomberg less CGS)
(A) Five year BBB rated		8.84	5.37	3.46
(B) Seven year BBB rated		9.43	5.53	3.90
(C) Six year BBB rated	[(A) + (B)]/2			3.68
(D) Five year AAA rated		6.16	5.37	0.79
(E) Seven year AAA rated		6.63	5.53	1.10
(F) Six year AAA rated	[(D) + (E)]/2			0.95
(G) Ten year AAA rated		7.19	5.65	1.54
Proposed DRP on 10 year BBB+ rated bonds	(C)+(G)-(F)			4.28

Note:

1. Values are annualised as required by clause 6.5.2(e) of the NER.
2. Values may not sum due to rounding.

11.9 Forecast inflation

JEN proposes an inflation forecast of 2.57 per cent, which incorporates the method used by the AER in its draft decision.

JEN estimate of forecast inflation, which is consistent with the AER’s draft decision, is calculated as the geometric average of the forecast annual inflation for each of the ten years from 2011 to 2020:

Table 11-5: Forecast inflation (per cent per year)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inflation Forecast	2.75	3.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Geometric Average										**2.57**

Note: Inflation forecasts are for the year to June.

Source: Reserve Bank of Australia, Statement on Monetary Policy, 6 May 2010, page 56, table 14.

JEN’s explanation of the ten annual inflation forecasts above are as follows:

- *first two years*–the forecasts are the expected inflation outcomes stated in the Reserve Bank of Australia's (RBA's) most recent Statement on Monetary Policy
- *subsequent eight years*–the forecasts are the midpoint of the RBA's long term inflation target range. The forecast range is 2 to 3 per cent, so the midpoint is 2.50 per cent.

11.10 JEN's revised regulatory proposal

JEN proposes to amend its regulatory proposal to delete Tables 9-1 and 9-4 and replace both of them with the Table 11-6.

Table 11-6: JEN's revised WACC Parameters

Parameters	JEN Proposal
Inflation (i)	2.57%
Nominal risk-free rate (R_f^n)	5.65%
Real risk –free rate	3.00%
Debt margin (D^n)	4.28%
Nominal pre-tax cost of debt	9.93%
Real pre-tax cost of debt	7.17%
Market risk premium (MRP^n)	6.50%
Equity beta (β_e)	0.80
Post-tax nominal return on equity	10.85%
Gearing (D/V)	60%
Nominal vanilla WACC	**10.29%**
Real vanilla WACC	7.53%

Notes:

1. Real costs of debt and equity and the risk free rate are calculated from the nominal equivalents using the Fisher equation and forecast inflation.
2. Debt margin is based on an efficient electricity business with a BBB+ credit rating.
3. JEN does not rely on a debt or asset beta to estimate its proposed WACC.

12 Estimated corporate income tax

- JEN considers that there is persuasive evidence to justify a departure from the value of assumed utilisation of imputation credits (**gamma**) in the SORI.
- JEN uses a gamma estimate of 0.2 because it is a better estimate than the AER's for two reasons—the AER's payout ratio of 1 is not backed by empirical evidence and JEN's 0.23 estimate of theta is more reliable and based on more recent data than the AER's estimate of 0.65.
- JEN uses the diminishing value depreciation method to calculate tax depreciation, consistent with the AER's draft decision.
- JEN uses the current corporate tax rate of 30 per cent to calculate the cost of corporate income tax. JEN does not incorporate the planned changes to the tax rate that were announced in the 2010 Federal Budget as they do not reflect current tax law.

12.1 Summary of JEN original regulatory proposal

In its original regulatory proposal, JEN proposed a value of imputation credits (or gamma) of 0.2,[359] which is a departure from the 0.65 contained within the SORI. JEN argued that there was persuasive evidence that justified a departure from the value in the SORI in accordance with clauses 6.5.4(g) and 6.5.4(h) of the Rules (see section 12.1.1).

Gamma is the market value of the imputation credits that are created by a firm, and is conventionally defined as the product of the assumed proportion of the credits created that are distributed to investors (the payout ratio **F**) and the market value of imputation credits once in the hands of investors (**theta**). JEN proposed values of 0.66 for F and 0.23 for theta and a gamma point estimate of 0.2.

Along with a gamma of 0.2, JEN also proposed to use diminishing value tax depreciation and a corporate tax rate of 30 per cent to estimate the corporate income tax allowance.

12.1.1 Persuasive evidence for a departure from the SORI

JEN cited similar concerns to those raised by ETSA Utilities in the South Australian distribution price review process in relation to the payout ratio, including:

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[359] The draft decision considered imputation credits (gamma) in the taxation chapter. Accordingly, gamma is addressed in this chapter of the submission.

- expert evidence of Professor Robert Officer[360] (architect of the Officer framework) and tax lawyer Peter Feros,[361] who both reject the assumption that all imputation credits are distributed to shareholders

- the Officer and Hathaway (2004) study estimated a payout ratio of 0.71[362]

- the Synergies report (2009) found that between 2003 and 2007 the payout ratio averaged 66 per cent, based on tax statistics.

JEN also argued that the value of theta should be less than that set in the SORI, and submitted evidence to support this claim, including:

- a report by Professor Skeels reviewing the SFG study, which produced a substantially lower value of theta

- the Synergies report (2009) estimates that investors on average only utilise 35 per cent of the credits that they receive.

Professor Skeels noted that the AER arguments against the use of the SFG study were "unconvincing" and were in fact nothing more than allusions to potential problems which required further investigation. Professor Skeels conducted such an investigation of the SFG study and found its results to be convincing. His report concluded:[363]

> This leads me to consider that their [SFG's] estimate of theta of 0.23 is the best such estimate currently available for Australia. It might be argued that their methodology does not perfectly replicate that of Beggs and Skeels (2006) and that the remaining differences may downwardly bias the estimates provided by SFG in Appendix I. I am not one who shares that view as I think their analysis is now compelling. However, if one was to take that view then I think that a very strong case could be made for the true value of theta to lie somewhere between the SFG estimate of 0.23 and the Beggs and Skeels (2006) estimate of 0.57, and in all probability to lie towards the lower end of that range. Any higher value for theta seems completely implausible, both in terms of the empirical evidence presented and in terms of the theoretical arguments underpinning them.

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360 Robert R. Officer, *Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers*, 23 June 2009. See Appendix 12.5.

361 Peter Feros, Review of WACC parameters: Gamma, ETSA Price Reset, 22 June 2009. See Appendix 12.22.

362 N. Hathaway and B. Officer, *The Value of Imputation Tax Credits – Update 2004*, Capital Research Pty Ltd, November 2004, pp.13 and 24. See Appendix 12.4.

363 Christopher L Skeels, *A Review of the SFG Dividend Drop-Off Study – A Report prepared for Gilbert and Tobin*, 28 August 2009, p. 31. See Appendix 12.14.

12.2 Summary of AER's draft determination and decision

The AER did not consider that JEN's submission provided persuasive evidence justifying a departure from the gamma value of 0.65 set in the SORI. The AER considers that the value of 0.65 is the most appropriate estimate of gamma based on the reliable evidence currently available.

The AER drew on two new reports by:

- Associate Professor John Handley of the University of Melbourne (**Handley Report**) [364]
- Professor Michael McKenzie and Associate Professor Graham Partington on behalf of the Securities Industry Research Centre of Asia-Pacific (**McKenzie and Partington**).[365]

In relation to the payout ratio, the AER stated that the evidence presented by JEN had already been considered as part of the WACC review. The AER repeated its contention that a payout ratio of 100 per cent is consistent with the Officer WACC framework, which assumes that cash flows occur in perpetuity and are therefore fully distributed at the end of each period. The AER also asserted that even where imputation credits are retained, they will still hold value. The AER noted and agreed with the advice of its experts (including McKenzie and Partington) that the actual payout ratio is likely to be between 70 per cent and 100 per cent. Nonetheless, the AER adopted a value at the top of this range, noting that "the assumption of a 100 per cent payout ratio simplifies the framework for estimating gamma".[366]

In relation to theta, the AER stated in its Draft Decision that it does not consider the report by Professor Skeels to represent persuasive evidence. The AER noted that although Professor Skeels appeared to address a number of the AER's concerns with the SFG study, there were still a significant number of issues which demonstrated that SFG's estimates were likely to be unreliable.

The AER draft decision relied heavily on the two new reports and expressed the following concerns:

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364 Associate Professor John Handley, 19 March 2010, *Report prepared for the AER on the estimation of gamma*. See Appendix 12.28.

365 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*. See Appendix 12.27.

366 AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, p. 537.

- McKenzie and Partington's analysis demonstrates that SFG's regression results are likely to be affected by multicollinearity and as a result the values of imputation credits are likely to be downwardly biased[367]

- the SFG study has problems with consistency in parameter estimation and data reliability remains an issue

- based on McKenzie and Partington's advice, SFG's use of the Cook's D-statistic is likely to be less reliable than the filtering methodology used by Beggs and Skeels (2006)[368]

- the number of zero and negative drop-offs in SFG's data set is abnormally high

- the AER notes the conclusions of the Handley Report that taxation studies may provide a reasonable estimate of the upper bound for theta.

The AER's draft decision also reflects recent amendments to tax legislation affecting diminishing value rates used for tax depreciation as well as proposed changes to the statutory corporate income tax rate.[369] The AER proposes a reduction in the assumed corporate tax rate in the later years of the regulatory period to reflect recently announced changes to Federal Government tax policy.

12.3 JEN's response to AER's draft determination and decision

Table 12-1 summarises JEN's responses to the AER's draft decision.

[367] AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, pp. 542–545.

[368] AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, p. 548.

[369] AER, *Victorian Draft Distribution Determination—Draft Decision*, June 2010, p. 556.

Table 12-1: JEN's responses to the AER's draft decision – taxation

Change	Related AER amendments	JEN revised regulatory proposal	Summary of explanation	Explanation in this document
Assumed utilisation of imputation credits (gamma)	Section 12.6.1	Not incorporated	Gamma of 0.2 is a better estimate because (a) the AER's payout ratio of 1 is not backed by empirical evidence and (b) a 0.23 estimate of theta is more reliable and based on more recent data than the AER's estimate of 0.65	Section 12.4
Tax depreciation	Section 12.6.2	Incorporated	Use tax rates and method used by AER in its draft decision	Section 12.5
Corporate tax rate	Section 12.6.2	Not incorporated	Use corporate tax rate of 30 per cent for 2011 to 2015 because reflects current tax law	Section 12.6

JEN provides detail on its response to the AER's draft decision below.

12.4 Value of imputation or franking credits (gamma)

JEN has not incorporated the AER's gamma estimate of 0.65. JEN proposes a gamma estimate of 0.2 because it reflects the best estimate in the circumstances, relying on persuasive evidence presented, together with JEN's original proposal, in Appendices 12.2 to 12.41 of this revised proposal. JEN considers that this evidence justifies a departure from the SORI in accordance clause 6.5.4(g).

The rest of this section explains why JEN considers a gamma of 0.2 is a better estimate than 0.65 and is set out as follows:

- the Rules require an estimate of gamma

- although the SORI sets gamma at 0.65, the Rules permits a departure from this value in certain circumstances, which JEN considers have been demonstrated to exist

- the best estimate of the payout ratio is 70 per cent, not 100 per cent

- the best estimate of theta is 0.23, not 0.65

- combining the payout ratio and theta estimates, the best estimate of gamma is 0.2.

12.4.1 National Electricity Rules require an estimate of gamma

The National Electricity Rules (**NER**) require an assumption regarding the utilisation of imputation credits to calculate the cost of corporate income tax of a DNSP for each regulatory year. Clause 6.5.3 of the Rules requires that the cost of corporate income tax be calculated in accordance with the following formula:

$$ETC = (ETI \times r)(1 - \gamma)$$

where:

ETI is the estimated taxable income for the regulatory year;

r is the statutory income tax rate; and

γ (gamma) is the assumed utilisation of imputation credits.

JEN considers that gamma should be estimated as a market wide parameter for the Australian economy and defined (using the Monkhouse definition[370]) as the product of:

- the imputation credit **payout ratio**—the face value of imputation credits distributed by the firm as a proportion of the face value of imputation credits generated by the firm in the period

- the utilisation rate (**theta**)—the value of distributed credits to investors as a proportion of their face value.

The AER adopts this same definition in its draft decision.[371]

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370 P. Monkhouse, 1997, *Adopting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System*, Accounting and Finance, 37, vol. 1, pp. 69–88. See Appendix 12.24.

P. Monkhouse, 1993, *The cost of equity under the Australian dividend imputation tax system*, Accounting and Finance, vol 33, pp. 1-18. See appendix 12.25.

371 AER, June 2010, *Victorian Draft Distribution Determination—Draft Decision*, p. 528.

The Rules also require the AER to carry out a review of rate of return parameters every five years and issue a Statement of Regulatory Intent (**SORI**) adopting values, methods and credit rating levels for DNSPs or specified classes of DNSPs.[372]

12.4.2 SORI sets gamma at 0.65, but the Rules allow for a departure

The AER issued its SORI on 1 May 2009, which set gamma at 0.65. The Rules allows for departure this value if there is persuasive evidence, which JEN considers does exist.

In the decision document accompanying the SORI, the AER justified this on the grounds that:[373]

- an assumed payout ratio of 100 per cent appeared reasonable and consistent with the Officer framework
- the value of theta should be 0.65, being the midpoint of the values produced by dividend drop-off studies and taxation studies.

The SORI marked a significant departure from previous regulatory practice in respect of the value of gamma. Prior to the SORI, the ACCC and various state regulators had all adopted a value for gamma no greater than 0.5 (in some cases a value for gamma below 0.5 had been adopted).[374]

The underlying criteria used by the AER in its SORI were based on the revenue and pricing principles in section 7A of the National Electricity Law, and the factors that the AER is required to have regard to under clause 6.5.4(e) of the NER. The AER states in the Draft Decision that its underlying criteria were:[375]

- the need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services
- the need to achieve an outcome that is consistent with the national electricity objective
- the need for persuasive evidence before adopting a value or method that differs from the value or method previously adopted

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372 NER, clause 6.5.4.

373 AER, May 2009, *Electricity transmission and distribution network service providers review of the weighted average cost of capital (WACC) parameters: final decision*, p. 466. See Appendix 12.29.

374 AER, May 2009, *Electricity transmission and distribution network service providers review of the weighted average cost of capital (WACC) parameters: final decision*, p. 396.

375 Draft decision, pp. 529–530.

- the relevant revenue and pricing principles, which are:
  - providing a service provider with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services and complying with a regulatory obligation or requirement or making a regulatory payment
  - providing a service provider with effective incentives in order to promote efficient investment
  - having regard to the economic costs and risks of the potential for under and over investment.

The only dividend drop-off study relied upon by the AER was the study by Beggs and Skeels (2006),[376] which produced an estimate for theta of 0.57. The AER did not place any weight on the more up-to-date findings of the SFG (2009) dividend drop-off study,[377] which produced substantially lower estimates of theta. The AER relies on tax studies to provide an "upper bound" for theta. It derives an upper bound of 0.74, being the mid-point of the range of values from the tax studies (the range being 0.67 to 0.81).

A distribution determination to which a SORI is applicable must be consistent with the SORI unless there is "persuasive evidence justifying a departure, in a particular case, from a value, method or credit rating level set in the statement".[378] In determining whether a departure from a SORI is justified in a distribution determination, the AER is required to consider:[379]

- the criteria on which the value, method or credit rating level was set in the SORI (the underlying criteria)
- whether a material change in circumstances since the date of the SORI, or any other relevant factor, now makes the value, method or credit rating level set in the SORI inappropriate.

376 David J. Beggs and Christopher L. Skeels, September 2006, *Market Arbitrage of Cash Dividends and Franking Credits*, The Economic Record, Vol. 82, No. 258, pp. 239–252. See Appendix 12.15.

377 SFG, May 2009, *The value of imputation credits as implied by the methodology of Beggs and Skeels (2006)*, referenced in:

C. Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study*, p. 3. See Appendix 12.14.

378 NER, clause 6.5.4(g).

379 NER, clause 6.5.4(h).

12.4.3 *The best estimate of the payout ratio is 70 per cent, not 100 per cent*

JEN considers that it is inappropriate to adopt the AER's assumed dividend payout ratio of one and that 70 per cent is the best estimate in the circumstances.[380]

The AER's payout ratio of one implicitly makes two important assumptions:

- undistributed credits will eventually be distributed
- there is no difference in value between distributed and undistributed credits.

JEN considers that both assumptions are incorrect and that empirical evidence provides the best estimate of the payout ratio in the circumstances. Empirical evidence strongly suggests a payout of significantly less than one. The AER provided no new empirical evidence to the contrary in its draft decision.

JEN supports its proposed payout ratio by making the following arguments:

- there is no evidence that undistributed credits will eventually be distributed as the AER claims
- undistributed credits should have a substantially lower value than distributed credits
- the Officer framework does not require a payout ratio of one
- the AER's own expert advisors agree that the actual payout ratio is less than one
- the AER's imputation credit payout ratio of one is not backed by empirical evidence; rather, the weight of empirical evidence supports a payout ratio of 70 per cent.

There is no evidence that undistributed credits will eventually be distributed

The expert evidence of Mr Feros demonstrates that there are a number of legal and regulatory impediments to distribution of retained credits.[381] Additionally, there will be practical impediments to distribution since companies will build up large amounts of retained credits as they only distribute, on average, around 70 per cent of those created in each year.

[380] As noted recently by ETSA. ETSA Utilities, 14 January 2010, *Revised Regulatory Proposal 2010–2015*, p. 191. See Appendix 12.26.

[381] Peter Feros, 22 June 2009, *Review of WACC parameters: Gamma, ETSA Price Reset*. See Appendix 12.22.

Over time, companies will need to distribute more credits than are actually created in order to distribute retained credits. That the 70 per cent figure is an average and that over time businesses do not generally distribute more credits than are actually created is obvious from the large amounts of retained credits revealed in the Australian Taxation Office statistics—the Handley Report notes that the aggregate balance of retained imputation credits at the end of June 2007 totalled almost $150 billion.[382] It would also explain the tendency for franking account balances to rise over time, noted by McKenzie and Partington.[383]

Assuming a payout ratio of one is not only inconsistent with the empirical evidence, but also ignores the practical constraints on the ability of firms to pay out retained credits. In general, a firm will only be able to distribute retained imputation credits in years where it distributes more credits than it creates (that is, in years when the payout ratio is greater than one). This might be possible for some companies with substantial foreign income or a desire to lower equity levels, but it is unlikely to be the case for regulated energy businesses such as JEN with a growing regulatory asset base. JEN's ability to pay out retained credits in any given year is restricted by both its assumed financing structure (particularly gearing) and the nature of its income streams.

JEN also notes that the pool of retained credits is growing over time,[384] which suggests that firms are struggling to pay out these credits and that investors are not able to access this value. So, even if these credits were eventually paid out, JEN considers that they would not be paid out within five years of being earned.

The AER does not have any empirical evidence to support its assumption that retained credits will be distributed soon after retention. The AER says it is uncertain as to how long firms are likely to retain credits and says it is not aware of any empirical research on the retention period.[385]

Rather, it is simply assumed that retained credits will be paid out within a one to five year period, when there is in fact no reason to believe that the payout period would necessarily match the regulatory period. The AER also ignores the evidence referred to above which demonstrates the significant constraints on the ability of companies to distribute retained credits in a timely manner.

Professor Handley argues that there are ways in which the value of retained credits may be "unlocked", including through off-market buy-backs and dividend re-

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382 Associate Professor John Handley, 19 March 2010, *Report prepared for the AER on the estimation of gamma*, p. 36. See Appendix 12.28.

383 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 27. See Appendix 12.27.

384 NERA, 5 January 2010, *Payout ratio of regulated firms*, report for Gilbert and Tobin, p. 6. See Appendix 12.17.

385 Draft decision, p. 537.

investment plans. However, the use of such mechanisms is likely to be relatively limited and will not significantly affect the overall balance of retained imputation credits. In any case, the use of such mechanisms will already be reflected in the distribution rate studies, including those of Officer and Hathaway (2004) and NERA (2010). These studies consider the total amount of credits distributed by *any* means (including those referred to by Professor Handley) as a share of credits created.

Undistributed credits should have a lower value than distributed credits

Investors will discount the value of undistributed credits. This is recognised by the AER's own experts.[386]

The extent of discounting depends on investors' discount rates and the time it takes for retained credits to be distributed (discussed above). Even where the discount rate is low, the discounted value of retained credits will be very small if it takes a long time for retained credits to be distributed.

Given the evidence relating to the rate of retention of credits by companies and the constraints on distribution once these credits are retained, JEN considers it likely that investors would heavily discount the value of retained credits. Therefore, the payout ratio should closely reflect the actual distribution rate of 70 per cent which is supported by the empirical evidence and recognised by the AER's expert advisors.

Officer framework does not require a payout ratio of one

A payout ratio below 100 per cent would not be inconsistent with the Officer CAPM framework as the AER claims in its draft decision.[387] Professor Officer himself has stated that the Officer framework says nothing about the payout ratio:[388]

> The Officer (1994) paper implicitly assumes that the [value of the imputation credits] reflects the value of the credits at the time they are distributed which is consistent with paying them out immediately or them being subject to significant (even infinite) delays.

Professor Officer further states that:[389]

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[386] Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 25. See Appendix 12.27.

[387] The Officer framework was first developed in:

R. Officer, 1994, *The cost of capital of a company under an imputation tax regime system*, Accounting & Finance, Vol 34, Issue 1, pp. 1–17. See Appendix 12.30.

[388] R. Officer, 23 June 2009, *Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers*, p. 3. See Appendix 12.5.

[389] R. Officer, 23 June 2009, *Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers*, p. 3. See Appendix 12.5.

> my original paper (Officer, 1994) did not address the issue of a variable distribution, the paper's conclusions are consistent with an immediate or full payout of earnings or a delayed payment.

The Officer (1994) paper did not deal with the payout ratio directly. Rather it made the simplifying assumption that imputation credits were valued at the time they were distributed. Such simplifying assumptions are common in academic analysis and are not necessarily intended to reflect reality or constrain economic models such as the Officer CAPM from applying to real world situations.

Assuming a 100 per cent payout ratio implies that firms do not grow from internal resources,[390] which cannot hold in reality. Helpfully, Dr. Neville Hathaway demonstrates that, despite the AER's contentions, the Officer CAPM *can* model firms that grow by retaining earnings and therefore delaying the payout of dividends and imputation credits to shareholders.[391]

The Officer CAPM is one of a class of robustly derived tax-adjusted CAPMs where gamma (and thus implicitly the payout ratio) is variable, not something that needs to be assumed.[392] For instance, Associate Professor Lally notes that:[393]

> Within the context of the Officer model, the [payout ratio] is firm specific. Variation across firms will arise from variation in the ratio of Australian company tax paid to Australian sourced "profits", and variation in the ratio of cash dividends to "profits".

Instead, empirical data provides better estimates of the payout ratio than theoretical assumptions, such as that made by the AER—a view supported by SFG:[394]

> [T]he distribution rate should be estimated using empirical data from the real world, rather than assuming a hypothetical value.

AER experts agree that the actual payout ratio is less than one

The AER's expert advisors would appear to agree that that the payout ratio is less than 100 per cent and hence that assuming 100 per cent payout would lead to an

390 Neville Hathaway, July 2010C, *Practical Issues in the AER Draft Determination*, p. 14. See Appendix 12.12.

391 Neville Hathaway, July 2010C, *Practical Issues in the AER Draft Determination*, pp. 12–13 and 15–21. See Appendix 12.12.

392 M. Lally, 2000, *Valuation of companies and projects under differential personal taxation*, Pacific-Basin Financial Journal, vol. 8, pp. 115–133. See Appendix 12.18.

393 M. Lally, June 2002, *The cost of capital under dividend imputation*, prepared for the ACCC, p. 18. See Appendix 12.18.

Associate professor Lally defines, consistent with the WACC framework, the 'payout ratio' as the ratio of imputation credits assigned by a company during a period (IC) to company tax paid during that period (TAX) i.e. IC/TAX.

394 SFG, 15 July 2010, *Issues relating to the estimation of gamma,* p. 9. See Appendix 12.6.

overstatement of gamma. The only issue in the minds of these experts is the extent to which the payout ratio should be below 100 per cent to reflect the lower value of undistributed credits. For the reasons set out above, JEN considers that little value should be assigned to undistributed credits and hence the payout ratio should be significantly below 100 per cent.

McKenzie and Partington refer to the actual payout ratio as being "about 70%",[395] in line with the findings of Officer and Hathaway (2004) and more recently NERA (2010).[396] McKenzie and Partington go on to conclude that the appropriate payout ratio for the purposes of estimating gamma should lie between 70 per cent and 100 per cent, since undistributed credits will have at least some value. It is noted that the AER implicitly assumes that either there is 100 per cent payout (an assumption which McKenzie and Partington consider to be unrealistic) or undistributed credits have the same value as distributed credits:[397]

> The AER makes the assumption that there is a 100 percent payout of imputation credits. Taken literally, this is clearly incorrect. However, we view the 100 percent payout assumption as simply a convenient step designed to allow for the value of undistributed franking credits when computing gamma. It is equivalent to saying that undistributed franking credits have the same value as distributed franking credits. In principle, this is likely to overstate the value of the undistributed credits, but it is not clear by how much.

McKenzie and Partington also consider the assumption that undistributed and distributed credits hold the same value to be unrealistic. They note that:[398]

> Clearly, undistributed credits will be discounted relative to distributed credits…

The Handley Report reaches a similar conclusion that the payout ratio lies between 70 per cent and 100 per cent. Professor Handley also considers the AER's assumption of full payout to be unrealistic, given the empirical evidence which demonstrates substantially lower payout, and the fact that investors are likely to discount the value of undistributed credits. Professor Handley notes:[399]

> An assumption that all credits are distributed in the period in which they are created will likely overstate the value of gamma.

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395 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 27. See Appendix 12.27.

396 NERA, 5 January 2010, *Payout ratio of regulated firms*, report for Gi bert and Tobin. See Appendix 12.17.

397 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma,* p. 26. See Appendix 12.27.

398 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 25. See Appendix 12.27.

399 Associate Professor John Handley, 19 March 2010, *Report prepared for the AER on the estimation of gamma*, p. 33. See Appendix 12.28.

Empirical evidence supports a payout ratio of 70 per cent

NERA has conducted new empirical analysis—provided in Appendix 12.17—of ATO statistics that clearly shows that the assumption of a 100 per cent payout ratio is inconsistent with the actual behaviour of firms.[400] NERA's analysis finds that on average 68 per cent of imputation credits were paid out between 1996-97 and 2006-07.401 This result is consistent with other available evidence on the payout ratio, including:

- the Hathaway and Officer[402] estimate of 71 per cent
- the Synergies[403] estimate of 66 per cent that JEN relied on in its original regulatory proposal
- the most recent estimate of 69 per cent provided by Hathaway.[404]

There is now a considerable volume of persuasive evidence before the AER that would justify a departure from the assumption of a 100 per cent payout ratio. In addition to the evidence presented by JEN in its November 2009 regulatory proposals—particularly the expert evidence of Professor Officer and Mr Feros and the findings of the Officer and Hathaway (2004) study—there is also new evidence and comment from NERA, Hathaway,[405] SFG,[406] and the AER's own expert advisors that demonstrates that the payout ratio is likely to be significantly less than 100 per cent.

Dr Neville Hathaway summarises his concerns with using a payout ratio of 100 per cent: [407]

> The assertion that the ultimate distribution of franking credits will be close to 100% over a five year period is incorrect. It flies in the face of all the evidence and all reason. The explanation of how companies are going to achieve this 100% payout is

400 NERA, 5 January 2010, *Payout ratio of regulated firms*, report for Gilbert and Tobin. See Appendix 12.17.

401 NERA, 5 January 2010, *Payout ratio of regulated firms*, report for Gilbert and Tobin p. 6. See Appendix 12.17.

402 N. Hathaway and B. Officer, November 2004, *The Value of Imputation Tax Credits – Update 2004*, Capital Research Pty Ltd, pp. 13 and 24. See Appendix 12.4.

403 Synergies Economic Consulting, 28 May 2009, *Gamma: New Analysis Using Tax Statistics*, p. 6. See Appendix 12.23.

404 Neville Hathaway, July 2010B, *Imputation Credit Redemption: ATO data 1988–2008*. See Appendix 12.3.

405 Neville Hathaway, July 2010C, *Practical Issues in the AER Draft Determination*. See Appendix 12.12.

406 SFG, 15 July 2010, *Issues relating to the estimation of gamma,* See Appendix 12.6.

407 Neville Hathaway, July 2010C, *Practical Issues in the AER Draft Determination*, p. 5. See Appendix 12.12.

> weak. Companies are struggling to maintain their historical payout ratios of just 70%. It has now dropped to 68% under the new tax system with the new rules for crediting the FAB. The suggested activities to achieve this 100% payout are already being practised and they are not delivering 70% payout, let alone 100% payout. If companies paid out the average of 68% for four years and then paid out all the retained credits at year 5, they would need to payout profits in year 5 at 228%. They must payout all retained profits over the last five years as an excessively large dividend in order to meet this 100% distribution of all credits. This is totally unrealistic. The retained profits will not be available for this payout and so the credits will not be 100% distributed.
>
> The related logic that “retained credits” have value is wrong. No matter what value one might put on these credits, it has to be multiplied by the probability of ever realising that value. For all practical reasons, that probability is zero. Unless the existing annual distribution of credits can be boosted to at least 100% per annum, the potential credits in the [Franking Account Balance] will never be accessed and are effectively worthless.
>
> Calling the [Franking Account Balance] “retained credits” is misleading as it implies that they are readily available to be accessed. There is currently over $170 billion recorded in the FABs of all Australian companies. But that pool can only be accessed [in conjunction with] with franked dividends as the tax payment only becomes credits when so issued.

12.4.4 The best estimate of theta is 23 per cent

JEN considers that the best estimate of the theta is 0.23—based on the SFG dividend drop-off study—and that the tax studies relied on by the AER are not reliable measures of theta.

JEN’s argument is set out as follows:

- all empirical studies of theta (including those relied on by the AER) potentially have limitations
- tax studies should not be relied on to estimate theta since they do not directly measure the value of imputation credits and may have methodological and data problems
- averaging theta estimates from tax and dividend drop off studies is not appropriate
- the best estimate of the utilisation rate (theta) is 0.23, based on the most recent dividend drop-off study from SFG.

Empirical studies of theta have limitations

The AER's consultants have noted the limitations of empirical studies in relation to theta generally, not just the SFG study of which the AER is critical of in its draft decision.

In light of these limitations, McKenzie and Partington recommend a balanced approach to the evidence on theta, taking into account all available sources of information. McKenzie and Partington state (emphasis added):[408]

> Ex-dividend studies and taxation studies however, both have limitations. Ex-dividend studies have substantial measurement and estimation issues and they involve analysis of trades in a restricted window. Taxation studies present results that apply across a broad sweep of investors, but they are subject to measurement problems (this has proven to be less of an issue since the introduction of the simplified tax system). Furthermore, the link between taxation statistics and the market value of imputation credits remains indirect. Therefore, neither type of study is likely to provide an accurate and definitive estimate of gamma on its own. **Given the uncertainty surrounding the estimates of gamma, we argue that it is preferable to consider evidence from multiple sources. This means considering results from both types of study and, where multiple studies of the same type are available, considering the results across these studies**.

McKenzie and Partington summarised this advice, which the AER did not follow in its draft decision, in even more explicit terms (emphasis added):[409]

> Given the problems inherent in estimating gamma using either taxation or ex-dividend studies, we argue in favour of a balanced approach. Since the best estimation techniques are beset with problems, the most logical approach is to consider the evidence on balance across all available sources. In this respect, the AER's approach of considering both ex-dividend and taxation statistics has merit, but **we would recommend a broader range of studies to triangulate the evidence considered by the AER**.

In the draft decision, the AER appears to have largely ignored this advice from its own consultants. The AER has relied on just one dividend drop-off (ex-dividend) study in Beggs and Skeels and ignored the more recent SFG study. Moreover, the AER appears to have ignored the limitations of the only tax study it relies on (Handley and Maheswaran (2008)).

The limitations of this taxation study and the AER's specific concerns with the SFG study are addressed in more detail below.

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[408] Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, pp. 9–10. See Appendix 12.27.

[409] Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 3. See Appendix 12.27.

Tax studies do not measure theta directly and may have data problems

JEN considers that tax studies should not be used to calculate the value of theta, since these studies provide no indication as to the value of imputation credits to investors, only the extent to which they are used.

However, if the AER is inclined to use tax studies, the findings of these studies should be interpreted with care, given the apparent problems with data used. JEN considers that the Handley and Maheswaran (2008) study is subject to a number of limitations and should, at best, be interpreted with extreme caution.

Tax studies—including those relied on by the AER—estimate the extent to which imputation credits are *used* by investors. The result of these studies is a ratio of credits redeemed in a given year to the number of credits created in that year. These studies provide limited information on the *value* of imputation credits to those investors that redeem them and therefore should not be used to calculate theta.

Tax studies would only be relevant to the value of theta if one assumed that the value of redeemed credits was equal to 100 per cent of their face value. If the value of these credits to redeeming investors was 50 per cent of their face value, then theta would be 50 per cent of the redemption rate.

The AER's expert advisors do not claim that tax studies provide a reliable *estimate* of theta, only that these studies provide a reasonable *upper bound*. In other words, theta will be no higher than the estimates produced by the tax studies, but could be significantly lower.

The Handley Report refers to the results of tax studies as an "upper bound" for theta,[410] noting that this term is used in the sense of a theoretical maximum, rather than in a statistical confidence interval sense. McKenzie and Partington note that:[411]

> the link between taxation statistics and the market value of imputation credits remains indirect.

These comments by the AER's expert advisors may reflect a recognition that the redemption rate of imputation credits will only reflect their value to investors if it is assumed that redeemed credits are fully valued. In practice this may not be a realistic assumption.

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[410] Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 15. See Appendix 12.27.

[411] Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*]., p. 9. See Appendix 12.27.

These comments are supported by Neville Hathaway who notes that: [412]

> [T]ax data give an overall measure of redeemed credits. The ATO data ought to give an upper bound for the gamma value of credits. After all, the capital value estimate is a "pay now collect later" measure whereas the ATO data are a measure of the eventual "collect" value.

JEN considers that the AER should not take into account these "upper bound" estimates from tax studies which are at best indirectly linked to the value of imputation credits. In calculating theta, it is inappropriate to average these theoretical maximum values with the point estimates produced by the dividend drop-off studies.

Notwithstanding the arguments against the use of tax studies (outlined above) if the AER maintains its view that these studies should be used, it should interpret their results with considerable caution. There are a number of issues with both the theoretical bases for these studies and the econometric techniques used.

The study relied on by the AER to derive its "point estimate"[413] for theta from tax statistics contains various qualifications and assumptions which should induce caution in interpretation. The study by Handley and Maheswaran (2008) produces an imputation credit redemption range of 0.67 to 0.81, from which the AER takes a mid-point of 0.74.[414] However, Handley and Maheswaran (2008) make a number of assumptions and qualifications in their study, which are not interrogated by the AER.

Most obviously, Handley and Maheswaran (2008) do not empirically estimate the redemption rate for imputation credits for the post-2000 period. The authors in fact assume that all credits will be redeemed by individuals and funds over this period, while estimating the redemption rate for non-residents.[415] It is not apparent what the basis for this assumption is, besides mere "investor rationality".[416]

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412 Neville Hathaway, July 2010B, *Imputation Credit Redemption: ATO data 1988–2008*, p. 1. See Appendix 12.3.

413 As noted above, it is incorrect to interpret this as a point estimate for theta, since the tax studies at best provide an upper bound.

414 John C Handley and Krishnan Maheswaran, March 2008, *A measure of the efficacy of the Australian imputation tax system*, *The Economic Record*, volume 84, number 264. See Appendix 12.21.

415 John C Handley and Krishnan Maheswaran, March 2008, *A measure of the efficacy of the Australian imputation tax system*, *The Economic Record*, volume 84, number 264, p. 90. See Appendix 12.21. In the bottom panel of Table 4, the utilisation rate is set to 1 for individuals and funds for each of the years 2001-2004 (for earlier years this takes a lower value).

416 John C Handley and Krishnan Maheswaran, March 2008, *A measure of the efficacy of the Australian imputation tax system*, *The Economic Record*, volume 84, number 264, p 86. See Appendix 12.21.

Nevertheless, it is clear that the estimate of redemption rates for this period cannot be relied on by the AER since it is based on assumption rather than empirical analysis. The use of this assumption in the post-2000 period may explain why the estimate produced by Handley and Maheswaran (2008) is substantially higher for 2001-2004, compared to the previous decade (0.81 compared to 0.67). Handley and Maheswaran (2008) also refer to a number of limitations in their data set and in particular the small sample size used.

Further problems are identified by Dr Neville Hathaway in his expert report on the Handley and Maheswaran (2008) study.[417] Dr Hathaway notes that some of the key limitations of this study include:

- the results appear to be contrived as they are based on analyses of data that the authors themselves have created by their assumptions
- data has been averaged over periods of materially different tax regimes, potentially distorting the results
- the methodology used to combine data for different groups introduces the risk of double counting.

Dr Hathaway concludes that:[418]

> [The Handley and Maheswaran] paper should not be used for application to corporate and regulatory issues within Australia. … The results are contrived as they are based on analyses of data that the authors themselves have created by their assumptions. …They ignore significant changes in the taxation regime associated with franking credits and miss important data.

and:[419]

> This paper does not address the access of investors to company tax via credits. It focuses solely on the credits of distributed dividends and does so via contrived tax statistics. Notwithstanding that tax statistics can only given an upper bound for theta, the problems with the estimates within this paper make it most unsuitable for practical use.

In a separate report, Dr Hathaway finds that the taxation data relied on by Handley and Maheswaran appears to be highly unreliable.[420] Dr Hathaway notes that there

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417 Neville Hathaway, July 2010A, *Comment on: "A Measure of the Efficacy of the Australian Imputation Tax System" by John Handley and Krishan Maheswaran*. See Appendix 12.2.

418 Neville Hathaway, June 2010A, *Comment on: "A Measure of the Efficacy of the Australian Imputation Tax System" by John Handley and Krishan Maheswaran*, p. 3. See Appendix 12.2.

419 Neville Hathaway, June 2010A, *Comment on: "A Measure of the Efficacy of the Australian Imputation Tax System" by John Handley and Krishan Maheswaran*, p. 3. See Appendix 12.2.

420 Neville Hathaway, July 2010B, *Imputation Credit Redemption: ATO data 1988-2008*. See Appendix 12.3.

are significant unexplained discrepancies in the taxation data and he concludes that these data should not be relied on for making conclusions as to the value of theta. Dr Hathaway concludes:[421]

> Until [the] reconciliation [of the “missing” $48 billion of credits between tax data, FAB data and dividend data] has occurred or it can be explained to me how to account for those credits, I urge all caution in using ATO statistics for any estimates of parameters concerned with franking credits

and:[422]

> Unfortunately, there are too many unreconciled problems with the ATO data for a reliable upper bound estimates to be made about theta and gamma. About the only consistent measure is the overall distribution fraction of 69%. This is the long term average estimate. The more recent estimate is 68%, the reduction caused by a change to the FAB being operated on a rolling tax paid basis. Gamma is the product of this distribution fraction and the value of a distributed credit, theta, and as theta is very unclear from the ATO data then so is gamma unclear.

Given these limitations, the results of the Handley and Maheswaran (2008) study should be interpreted with extreme caution.

Averaging theta estimates from tax and dividend drop off studies is not appropriate

JEN does not agree that an average of theta estimates from tax statistics and dividend drop-off studies—the method used by the AER—is appropriate in the circumstances. As noted above, JEN considers that tax statistics do not represent economic values, provide at best an indirect measure of theta, and have a number of limitations, and so should not be used to estimate gamma in any case.

In the Draft Decision, the AER takes an average of the values from Beggs and Skeels (2006) and Handley and Maheswaran (2008) to derive its value of theta. The AER argues that this is a valid approach, since both of these values represent point estimates. The AER considers the value from Handley and Maheswaran (2008) to represent an “upper value within a range of reasonable point estimates” and not an upper bound for theta.[423]

This approach to estimating theta is methodologically flawed, since it takes an average of a point estimate (from the Beggs and Skeels (2006) dividend drop-off study) and an upper bound estimate (from the taxation study). This implies that the AER’s estimate of theta will be upwardly biased.

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421 Neville Hathaway, June 2010B, *Imputation Credit Redemption: ATO data 1988–2008*, p. iv. See Appendix 12.3.

422 Neville Hathaway, June 2010B, *Imputation Credit Redemption: ATO data 1988–2008*, p. 16. See Appendix 12.3.

423 Draft decision, pp. 551–552.

Tax statistics do not contain any information about the value of an imputation credit in the sense of what an investor would pay for it. The tax studies will only provide an upper bound for theta since there is an implicit assumption that credits are fully valued by the investors that redeem them. If credits are not fully valued, then the value of theta will be less than what is implied by the tax studies. This point is noted by the SFG report[424] and also by the AER's own consultants.[425]

A better estimate of the utilisation rate (theta) is 0.23

JEN considers that the May 2009 SFG dividend drop-off study (**the SFG study**) which estimates theta at 0.23 is the most reliable and current estimate.[426]

The SFG study is more comprehensive than the 2006 Beggs and Skeels dividend drop-off study[427] that the AER relies on in its draft decision because it uses a much larger cross-section of businesses and a longer, more recent data period. This view is confirmed by Skeels—a co-author of the 2006 Beggs and Skeels study—who considers that the SFG study provides the most accurate estimate of the value of theta.[428]

The AER's following criticisms of the SFG study are either overstated or do not apply:

- *Multi-collinearity*—JEN agrees with the AER that dividend drop-off studies are likely to suffer from some multi-collinearity.[429] However this issue will apply not only to the SFG study, but also the Beggs and Skeels study relied on by the AER.[430] The AER is inconsistent in expressing concerns about the SFG study but not applying those same criticisms to the Beggs and Skeels study. McKenzie and Partington's criticisms are generic to dividend drop off studies as a whole and not unique to SFG.

[424] SFG, 10 July 2010, *Issues relating to the estimation of gamma*, pp. 25–26. See Appendix 12.6.

[425] Associate Professor John Handley, 19 March 2010, *Report prepared for the AER on the estimation of gamma*, p. 15. See Appendix 12.28.

[426] SFG, May 2009, *The value of imputation credits as implied by the methodology of Beggs and Skeels (2006)*, referenced in:

C. Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study*, p. 3. See Appendix 12.14.

[427] C. Skeels and Beggs, 2006, *Market Arbitrage of Cash Dividends and Franking Credits*, The Economic Record in 2006, Vol. 82, pp. 239–252. See Appendix 12.15.

[428] C. Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study*, p. 5. See Appendix 12.14.

C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, section 3. See Appendix 12.11.

[429] Draft decision, pp. 542–545.

[430] Draft decision, p. 551.

McKenzie and Partington note that multicollinearity is a problem for dividend drop-off studies generally and therefore emphasise the importance of taking a balanced approach to the evidence:[431]

> The final area of concern for dividend drop off studies relates to the econometric issues surrounding the estimation of the regression equations. In particular, the issue of multicollinearity dominates as there is a perfect linear relationship between the size of the cash dividend and the franking credit… We conclude that the problems inherent to dividend drop off studies only serve to reinforce our view that a logical approach to estimating gamma is to consider the evidence on balance across all available sources and not rely on any one individual source.

Despite this clear advice from McKenzie and Partington, the AER has relied on just one dividend drop off study, presumably on the assumption that this study is not affected by the same econometric issues as it perceives in the SFG study. However, the expert report commissioned by the AER demonstrates that this is clearly not the case.

JEN also considers that the AER's concerns about multi-collinearity in the SFG study are overstated. The standard errors of the estimate do not suggest that multi-collinearity represents any material concern, as analysed in both the Skeels report[432] and the SFG report[433].

- *Filtering and data quality*—JEN considers that the SFG study does properly filter its data set to exclude observations based on shortcomings in the data or where the observations were unreliable on economic grounds. SFG has recently conducted a rigorous sample exercise that shows, after a review of some 236 ASX announcements in relation to 150 observations, there are negligible changes to the results previously reported by SFG.[434] This sample exercise was conducted in response to Dr John Field, an independent statistician, who prepared a statistically robust sampling methodology to be used to interrogate the SFG data set.[435]

  The AER has noted that the sampling methodology developed by Field implies a range of 6.2 to 16.7 per cent of "unacceptable" observations. Although this may be the case, the AER has given no consideration to the

[431] Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 5. See Appendix 12.27.

[432] C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, section 3.1. See Appendix 12.7.

[433] SFG, 13 January 2010, *Response to AER Draft Determination in relation to gamma*, paras. 19–34. See Appendix 12.7.

[434] SFG, 13 January 2010, *Response to AER Draft Determination in relation to gamma.* See Appendix 12.7.

[435] SFG, 13 January 2010, *Response to AER Draft Determination in relation to gamma*, p.17. See Appendix 12.7.

materiality of the "unacceptability" and its likely effect on the results. The simple fact of the matter is that is removing observations which are uninfluential will have little impact on the results. SFG have adopted a modified version of the Cook's D procedure which removed influential *and* unreliable observations.

Despite the AER's suggestion that the sampling exercise was of no useful purpose, what the sampling procedure has clearly shown is that the removal of any further observations has an immaterial effect on the results, with SFG's results being incredibly stable. After a re-calibration of the estimation following the removal of a handful of observations there was a change at the third decimal point.[436]

As a final observation, the SFG study has been subject to a much higher degree of scrutiny than the Beggs and Skeels (2006) study. Unlike the Beggs and Skeels (2006) study, the SFG data has been made available for comment and SFG have responded to any concerns of the AER. There has been no such interrogation of the Beggs and Skeels study notwithstanding that the paper was peer reviewed. It is also relevant that this paper was written to examine structural breaks in the tax system not to give an estimate for theta *per se*. Even Skeels himself has stated that in his opinion the SFG estimate is currently the best estimate available.[437]

- *Use of Cook's D Statistic*—the criticisms in the AER's draft decision surrounding the use of Cook's D Statistic have already been addressed by Skeels and SFG. SFG modified the Cook's D Statistic to identify the top one per cent of observations and then only exclude those which were unreliable, this application is not arbitrary and is justified on economic grounds.

  The AER has provided no examples of the types of decisions it may consider to be "jointly influential" or how this may manifest itself in the results. This is merely an allusion to a possible concern, but is not supported by anything other than an assertion of the AER.

  Skeels has reviewed this modified approach to the use of the Cook's D Statistic and commented that it is a reasonable trade off in terms of efficiency and accuracy.[438] Further, this statistical measure should also be considered in light of the other diagnostics and checks performed by SFG

[436] SFG, 13 January 2010, *Response to the AER draft determination in relation to gamma*, pp. 17–18. See Appendix 12.7.

[437] Christopher L Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study – A Report prepared for Gilbert and Tobin*, p. 31. See Appendix 12.14.

[438] See, Christopher L Skeels, 21 September 2009, *Response to AER Questions*, pp. 6–8. See Appendix 12.13.

including the standard errors of the results and the fact that the sampling exercise shows significant stability in the SFG estimate.

- *Zero and negative drop-offs*—McKenzie and Partington have criticised the data in the SFG analysis for containing a number of zero and negative drop-offs. McKenzie and Partington stated that the number of zero drop-offs observations in the SFG study is “higher than expected”.[439]

  However, there is simply no evidence provided to support this assertion. There is also no evidence as to the number of zero and negative drop-offs in the Beggs and Skeels (2006) study. The AER has not tested this aspect of the study on which it relies and it is quite possible that this study has a similar number of such observations.

  In relation to negative drop-offs, McKenzie and Partington have argued that negative and zero drop-offs may bias the sample and should be removed.[440] However, this ignores the fact that the negative or zero-drop off is caused by a purely random event which there is no basis to remove from the sample. In fact, excluding observations in this arbitrary manner would inevitably bias the results.

  SFG respond to the concerns raised by McKenzie and Partington in a new report for the Victorian electricity businesses and concludes:[441]

  > it would be wrong to routinely omit zero or negative drop-off observations. Such observations should only be omitted if they are erroneous, and there is no evidence of that.

- *Economically implausible results*—the AER criticises one set of SFG results where “the value of cash dividends is greater than one dollar, which is economically implausible”.[442] JEN notes the AER’s concern but reiterates the view of Associate Professor Skeels that:[443]

  > [i]f the point estimate is economically implausible but the confidence interval includes economically plausible values, as the preferred SFG results do, then the correct interpretation of the estimates is that they suggest that the true parameter is near to the boundary of economically plausible values. They do not suggest that the true

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439 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 38. See Appendix 12.27.

440 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 38. See Appendix 12.27.

441 SFG, 15 July 2010, *Issues relating to the estimation of gamma*, p. 18. See Appendix 12.6.

442 Draft decision, p. 543.

443 C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, p. 28. See Appendix 12.11.

parameter value is an economically implausible value. To attach an implausible interpretation to something when a plausible interpretation is equally probable does not constitute a fair assessment of the statistical evidence.

The above reasons why the AER's criticisms of SFG's report are unfounded are supported by the reports in Appendices 12.4, 12.6, 12.7 and 12.11.[444] These reports address concerns about the SFG study that the AER originally raised in the South Australian draft decision and raised again along with other concerns in its draft decision for JEN. Furthermore, Skeels suggests that the concerns raised by the AER are of little practical importance and that the SFG estimate is the most accurate estimate currently available.[445]

As noted in the SFG report in response to the draft decision, the AER also failed to address the two inconsistent assumptions it makes when deriving the return on capital:[446]

- the AER's empirical estimates of theta (and consequently gamma) are conditional on an estimated value of cash dividends of 80 cents per dollar
- the AER's estimate of the required return on equity using the CAPM is conditional on cash dividends being valued at 100 cents per dollar.

It is inconsistent and wrong for the AER to use two different values for the same parameter when estimating the return on capital. The Tribunal has previously recognised the importance of maintaining the mathematical integrity of the CAPM when estimating the WACC in the *GasNet* decision.[447] The AER must address this issue and cannot maintain its previous approach in violation of the *GasNet* principle.

JEN reaffirms its view that dividend drop-off studies provide the most reliable and accurate method for estimating theta. JEN considers that these studies better

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444 SFG Consulting, 13 January 2010, *Response to AER Draft Determination in relation to gamma*. See Appendix 12.7.

SFG Consulting, 4 January 2010, *Further analysis in response to AER Draft Determination in relation to gamma*. See Appendix 12.4.

C. Skeels, 13 January 2010, Response to Australian Energy Regulatory Draft Determination. See Appendix 12.11.

SFG, 15 July 2010, *Issues relating to the estimation of gamma*. See Appendix 12.6.

445 C. Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study*, p. 5. See Appendix 12.14.

C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, section 3. See Appendix 12.11.

446 See, SFG, 15 July 2010, *Issues relating to the estimation of gamma*. See Appendix 12.6.

447 *Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6. See Appendix 2.20.

satisfy the requirements of the rules than do tax statistics because they better reflect the true market or economic value of imputation credits.[448]

Whilst JEN considers the SFG estimate of 0.23 to be the most robust and reliable estimate of theta, JEN also notes the recommendation made by McKenzie and Partington for a "balanced approach" to be taken to the evidence.[449] Given the significant limitations of tax studies noted above, an alternative approach that balances the materials before the AER may involve averaging the estimates of Beggs and Skeels (2006) and SFG (2009). This would yield an estimate of theta of 0.4, and (using a distribution rate of 0.7) a gamma of 0.28.

An approach that takes an average of the estimates of Beggs and Skeels (2006) and SFG (2009) yields a value for theta that is significantly below that determined by the AER. In light of the recommendations from their experts, it is unreasonable for the AER to place so much weight on the findings of one dividend drop-off study (Beggs and Skeels (2006)), whilst ignoring the more recent evidence from SFG (2009). Although the AER has expressed several concerns with the SFG (2009) study, each of these concerns has been addressed above and in the supporting expert reports and would appear to be unfounded.

12.4.5 Combining the best payout ratio and theta estimates, the best estimate of gamma is 0.2

JEN proposes a gamma estimate of 0.2. Multiplying the payout ratio estimate of 0.70 and the theta estimate of 0.23, as per the Monkhouse definition, gives a gamma estimate of 0.16, which is within the range of 0 to 0.23 for the value of gamma in JEN's proposal. Even using an assumed payout ratio of one implies a gamma estimate of 0.23, which is also consistent with JEN's proposal.

The AER's reasoning in support of its value of 0.65 is deficient in at least the following areas set out below:

- *Payout ratio inconsistent with empirical evidence*—the AER has ignored the weight of empirical evidence which demonstrates that the distribution rate is not 100 per cent, and is in fact likely to be around 70 per cent. This includes the expert reports commissioned by the AER itself which acknowledge that the distribution rate is below 100 per cent

- *Officer framework does not require a 100 per cent payout ratio*—the AER continues to assert that a 100 per cent distribution rate is consistent with the

448 This is supported by: C Skeels, 13 January 2010, *Response to Australian Energy Regulator Draft Determination*, section 2. See Appendix 12.11. On page 10, Associate Professor Skeels states that "the face value of the franking credit overstates its value to the investor relative to that of the corresponding cash dividend".

449 Professor Michael McKenzie and Associate Professor Graham Partington, 25 March 2010, *Evidence and submissions on gamma*, p. 3. See Appendix 12.27.

Officer WACC framework, even though this has been denied by Professor Officer himself

- *The Handley and Maheswaran (2009) study is deficient and represents an upper bound, not a point estimate*—the AER has relied on the tax study by Handley and Maheswaran (2008) to derive an “upper bound” for theta, despite apparent deficiencies in this study. The AER also appears to have misinterpreted the results of this study in deriving its “upper bound”.

- *Tax and dividend drop off studies should not be average*—the AER’s approach to estimating theta as an average of a point estimate and an upper bound is methodologically flawed.

- *The SFG (2009) study should be relied upon*—the AER has relied on just one dividend drop-off study to estimate theta, notwithstanding the advice of its experts to take a more “balanced approach”. The AER continues to disregard the more recent SFG (2009) study, despite expert evidence to suggest that this study is at least as reliable as the Beggs and Skeels (2006) study.

Based on the weight of empirical evidence, JEN submits that the AER should adopt a theta of 0.23, a distribution rate of 0.7, giving a gamma of 0.2. There is no reasonable basis for the AER to continue to adopt 0.65, including in light of the recommendations made by its own consultants. As noted above, even an approach which averaged Beggs and Skeels (2006) and SFG (2009), together with a distribution rate of 0.7 would provide a resulting gamma estimate of 0.28, less than half of the value adopted by the AER.

Consistent with JEN’s proposed gamma estimate of 0.2, JEN proposes a payout ratio of 70 per cent for the purposes of calculating capitalised equity raising costs (see section 8.13.3).

12.5 Tax depreciation

JEN uses the diminishing value depreciation method to roll forward its tax asset base from 1 January 2006 through to 31 December 2015. This is consistent with the AER’s draft decision, the 2006 EDPR and clause 11.17.2(c) of the Rules.

The AER draft decision largely accepted JEN’s original proposed calculation of tax depreciation, except that the AER incorporated changes to tax depreciation rates for expenditure made from 10 May 2006 onwards.[450] JEN has incorporated these changes into its revised proposal.

[450] Draft decision, pp. 554–555.

12.6 Corporate tax rate

JEN does not incorporate the AER's estimate of the corporate tax rate and instead uses the rate of 30 per cent proposed in JEN's original proposal.

The AER draft decision incorporated recently announced Federal Government tax policy when estimating corporate income tax. JEN considers that the AER is incorrect to use this policy to estimate JEN's corporate income tax because:

- it does not reflect current Australian tax law
- the 'tax change event' pass through mechanism—allowed in the AER's draft decision and proposed by JEN in chapter 16 below—[451] is designed to cover any such policy change it if becomes law.

These points are discussed in more detail below.

12.6.1 The Federal Government's tax policy is not tax law

The AER draft decisions intends to reduce the corporate tax rate to 29 per cent in the financial year 2013-14 and then to 28 per cent thereafter to reflect recently announced changes to Federal Government policy on the corporate tax rate:[452]

> The AER also notes more recent changes to corporate taxation arrangements announced by the Commonwealth Government on 11 May 2010, arising out of the Henry Review. Specifically, the Commonwealth Government will reduce the corporate tax rate to 29 per cent for the 2013–14 financial year and to 28 per cent from the 2014–15 financial year. The AER has determined that these changes should be reflected in the expected statutory corporate income tax rate under 6.5.3 of the Rules and have been applied in the AER's modelling of the DNSPs' tax building block.

But, the above policy is not tax law and, as demonstrated recently, is subject to change.

On 2 July 2010, the Federal Treasurer announced that the corporate tax rate would no longer be lowered to 28 per cent from the 2014-15 financial year, as originally planned. Due to the fiscal impacts of the Government's concessions on the resources super profits tax, the corporate tax rate would not be lowered below 29 per cent.[453]

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[451] Draft decision, p. 726.

[452] Draft decision, p. 555.

[453] Federal Government, 2 July 2010, *Breakthrough Agreement with Industry on Improvements to Resources Taxation*, joint media release from the Treasurer, Prime Minister and Minister for Resources and Energy. See Appendix 12.42.

This recent policy shift strengthens JEN's argument that the AER should not assume that the proposed changes will become tax law as planned. For instance, if fiscal circumstances change or there is a change in government at the upcoming general election, then the proposed adjustment to the corporate tax rate may be the first policy to be abandoned.

12.6.2 The 'tax change event' pass through mechanism is designed to incorporate any change to tax law

The Rules includes provisions to pass through any changes to tax law (chapter 16 below). The pass through provides a simple and correct mechanism for dealing with the uncertainty of tax policy and JEN does not consider there to be any prudent reasons not to use it.

The AER should therefore assume, for the purposes of this EDPR, that the current tax rate of 30 per cent will continue to apply.

12.7 Estimated corporate income tax

Based on the above, JEN estimates its corporate income tax liability as set out in Table 12-2.

Table 12-2: JEN's revised forecast corporate income tax liability

$nominal	2011	2012	2013	2014	2015	Total
Tax payable	2.52	3.39	4.64	6.78	6.74	24.07
Less the value of assumed imputation credits	0.50	0.68	0.93	1.36	1.35	4.81
Corporate income tax liability	2.02	2.71	3.71	5.43	5.39	19.26

This forecast is calculated in JEN's regulatory model (see Appendix 18.1).

JEN considers that this forecast is consistent with clause 6.5.3 of the Rules, that incorporates a gamma estimate of 0.2, corporate tax rate of 30 per cent for 2011 to 2015, and diminishing value tax depreciation method.

13 Efficiency carryover amounts for 2006-10

- JEN has used actual 2009 opex and the AER's draft decision method to calculate its revised efficiency carryover amounts to add to the 2011-2015 BBRR
- JEN's revised efficiency carryover amounts total $40.7 million.

13.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN used the ESCV's 2005 EDPR efficiency carryover mechanism decision to calculate efficiency carryover amounts to include in the BBRR for the forthcoming regulatory control period. Based on estimated 2009 opex and actual 2006-2008 opex, JEN proposed efficiency carryover amounts totalling $49.7 million.

13.2 Summary of AER's draft determination and decision

In its draft decision, the AER approved the DNSPs using the ESCV's method to calculate efficiency carryover amounts for the 2011-15 BBRR. This included growth adjustment, adjustments for changes in capitalisation policy and application of the 2010 benchmark efficiency change into the opex base year roll-forward.

While the AER approved JEN's adjustment for changes in its capitalisation policy in 2008 and 2009, it also required JEN to provide further information supporting these adjustments in its revised proposal.

The AER also made adjustments to remove items not reflected in the ESCV's opex forecast including: movements in provisions, licence fees and related party margins.

Table 13-1 sets out the AER's adjustments to the benchmark opex against which it assessed JEN's opex efficiencies for 2006 to 2009 as well as the AER's proposed efficiency carryover amounts which total $54.8 million.

Table 13-1: AER efficiency carryover adjustments and calculation

Item	2006	2007	2008	2009	2010
Benchmark opex	59.4	60.4	61.6	62.9	64.4
Growth Adjustment			0.1	0.1	0.1
Capitalisation policy adjustment		-	4.6	4.6	4.6
Revised benchmark opex	59.4	60.4	66.2-	-67.6	69.1
Revised opex	53.5	57.3	48.3	47.2	
	2011	**2012**	**2013**	**2014**	**2015**
Carryover amounts	20.4	14.5	17.3	2.5	0

Source: AER DD, Table 13.5 and Table 13.6.

13.3 JEN's response to AER's draft determination and decision

JEN has recalculated its efficiency carryover amounts using actual 2009 opex and the method set out in the AER's draft decision in Table 13-3. JEN has also provided additional information regarding its 2008 change in capitalisation policy.

13.3.1 Change in capitalisation policy

The AER's draft decision noted and adjusted for JEN's change in capitalisation policy during the current regulatory period. It also requested that JEN provide further information explaining this change. JEN provides this below.

Original capitalisation policy

The opex forecasts approved by the ESCV reflected JEN's original overhead capitalisation policy. JEN implemented this policy through cost allocation and capitalisation rules contained in its SAP accounting systems.

Changed capitalisation policy

In 2008 JEN implemented the new WOBCA methodology which affected the allocation of corporate costs and the capitalisation of these costs relative to JEN's original capitalisation policy.

Impact of change on efficiency carryover calculation

Consistent with the AER's EBSS guideline, JEN needed to adjust for this capitalisation policy change when calculating efficiency carryover amounts. This was necessary to ensure the opex forecasts and actual opex where compared on a like-for-like basis and did not result in windfall gains or losses not attributable to efficiencies achieved by JEN.

The capitalisation policy change affects JEN's reported costs from 2008 onwards. The years relevant to the efficiency carryover calculation are 2008 and 2009. 2010 is irrelevant because the ESCV specification constrains the efficiency carryover calculation in year five to provide a zero carryover result.

This means JEN needed to find a way to quantify the impact of its change in capitalisation policy for 2008 and 2009. To the extent JEN had done this for 2010 as well in its original proposal, this year was redundant and can be ignored.

Quantifying the change in JEN's capitalisation policy for 2008 and 2009

JEN calculated the change as follows:

- *For 2008* – the difference between the pre-WOBCA capitalised overheads and the post-WOBCA capitalised overheads in 2008
- *For 2009* – the 2008 change escalated for inflation. This is a proxy because JEN does not have a 2009 counterfactual for the original overheads.

For 2008 JEN was able to identify both the original capitalisation policy value and the new WOBCA value. This was possible, because JEN's SAP accounting system still had the former overhead capitalisation and allocation rules in operation at that time. This meant JEN could take the former value from SAP and the new value from its regulatory accounts. JEN simply compared these to quantify the 2008 impact. Table 13-2 explains this calculation and the input data sources that JEN relied upon. It also shows how JEN escalated the 2008 impact to estimate the 2009 impact.

Table 13-2: JEN capitalisation policy change calculation ($ million nominal)

Calculation input	Source	Value	
SAP report on former capitalised overhead value using original policy	SAP report (confidential Appendix 13.2)	6.89	(a)
WOBCA capitalised overhead	JEN 2008 regulatory accounts ABR worksheet	2.55	(b)
2008 capitalisation change	**Calculation (a) minus (b)**	**4.34**	**(c)**
Inflation adjustment	ABS series 6401.0 CPI all groups weighted average of 8 capital cities Sept 2008 divided by Sept 2007 (reflecting ESCV inflation assumption of Sept CPI with a 1 year lag)	5.0%	(d)

Calculation input	Source	Value	
2009 capitalisation change	**Calculation (c) times (d)**	**4.55**	

The only part of this calculation not previously provided to the AER is the SAP report. JEN now provides this in confidential Appendix 13.2.

13.4 JEN's revised regulatory proposal

Table 13-3 sets out JEN's revised efficiency carryover amounts including the adjustments JEN has applied to the ESCV benchmarks as required by the AER's draft decision. JEN's revised efficiency carryover amounts total $40.7 million.

Table 13-3: JEN revised efficiency carryover amounts

Item	2006	2007	2008	2009	2010
Benchmark opex	59.41	60.35	61.57	62.92	64.38
Growth Adjustment	0.12	0.25	0.38	0.50	0.63
Capitalisation policy adjustment	-	-	4.61	4.61	-
Revised benchmark opex	59.53	60.60	66.55	68.04	65.01
Actual opex	54.42	57.38	48.29	51.21	48.19
	2011	**2012**	**2013**	**2014**	**2015**
Carryover amounts	16.82	11.71	13.60	-1.44	-

14 Efficiency benefit sharing scheme

- The AER's draft decision retained the efficiency benefit sharing scheme (**EBSS**) specification included in the AER's framework and approach, this included identifying certain uncontrollable costs from the EBSS calculation
- JEN considers that the list of excluded uncontrollable costs should also include: additional EWOV costs associated with the AER's new tariff reassignment dispute resolution process, ombudsman scheme and ESV fees and HV injection claims.

14.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN proposed that the 2011-15 EBSS apply as set out in the AER's EBSS Guideline including the specification of future growth adjustments. JEN did not propose to exclude any cost categories from the EBSS in the forthcoming regulatory control period.

14.2 Summary of AER's draft determination and decision

The AER's draft decision retained the EBSS specification from its framework and approach. It also set out that it would exclude the following uncontrollable costs from the 2011-15 EBSS calculation:

- debt raising costs
- self insurance
- superannuation
- non-network alternatives
- DMIA
- GSL payments.

14.3 JEN's response to AER's draft determination and decision

JEN agrees with the AER's proposed 2011 to 2015 EBSS specification. However, JEN considers that certain additional cost items should be categorised as uncontrollable and excluded from the EBSS calculation.

14.3.1 Additional uncontrollable opex cost categories

In addition to the uncontrollable opex cost categories identified by the AER in its draft decision, JEN proposes that the following uncontrollable costs also be excluded:

- *New tariff assignment dispute resolution process costs* – EWOV costs associated with the new tariff assignment and reassignment dispute resolution process (see section 7.3.6 and Table 4-1) should be excluded from the EBSS because they arise from a change in regulatory obligation in the AER's draft decision which will cause DNSPs to incur variable and uncontrollable costs

- *Ombudsman scheme costs* – JEN contributes annual fees to EWOV to fund its operations. As the annual fee for each of the industry contributor is determined by the number of complaints being investigated against each company, the fees can vary year on year and therefore they should be excluded from the EBSS because these are uncontrollable by the DNSPs

- *Energy Safe Victoria fees* – JEN pays annual fees to the ESV (formerly the Office of the Chief Electrical Inspector) both for ESV fees and for the annual Victorian Electrolysis Committee fee. These fees can vary for reasons outside of DNSPs' control and they should therefore be excluded from the EBSS because these are uncontrollable by the DNSPs

- *HV injection claims* – payments made to customers for loss caused by supply outages or HV injections due to third party damage to assets. While some outages are due to technical failures of the network system, others are caused by external uncontrollable factors. Major climate related events like the smoke from bushfires, abnormal heatwave conditions or third party hits to network assets that result in HV injection claims that are outside the DNSP's control should be excluded from the EBSS.

15 Service target performance incentive scheme

- The AER's draft decision rejects the impact of climate change on future performance, and revises JEN's MAIFIe target.
- The AER also appears to overlook the almost certain decline in reliability that will arise from rejecting significant components of JEN's capex forecast.
- JEN's revised service target performance incentive scheme (**STPIS**) includes the following variations from its original regulatory proposal:
  - adoption of the national garanteed service level (**GSL**) framework from the current Victorian GSL framework
  - update forecast 2010 reliability based on the average of 2006-2009 actual performance
  - incorporated AER intent on calculating major event day (**MED**) threshold.

15.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN proposed to adopt the AER's proposed STPIS largely as specified by the AER but with specific arrangements to address issues of error or inappropriate incentives within the AER's proposed STPIS relating to:

- measurement of MAIFI in accordance with the ESCV's S factor (referred to as MAIFIe within the international standard IEEE-1366) rather than the definition in the STPIS
- the formula for incorporating the STPIS into annual allowed price movements
- the fixing of the MED threshold for the entire period to ensure regulatory certainty to assist in achievement of STPIS objectives
- the calculation of the MED threshold to reflect the relevant clauses within the AER's STPIS documentation
- performance targets (except fault call centre performance) to be based on data from 2005-2009

- fault call centre performance based on average of 2008 and 2009 performance, not five years.

JEN has also prepared a true-up for the financial consequences of the ESCV's to-be-discontinued S factor scheme.

Consistent with the AER's STPIS, JEN's opex and capex plans have been designed to maintain reliability performance at the current five year average historical level. They have also been designed to deliver improved customer service during major emergency events and continue to foster a positive customer service business culture.

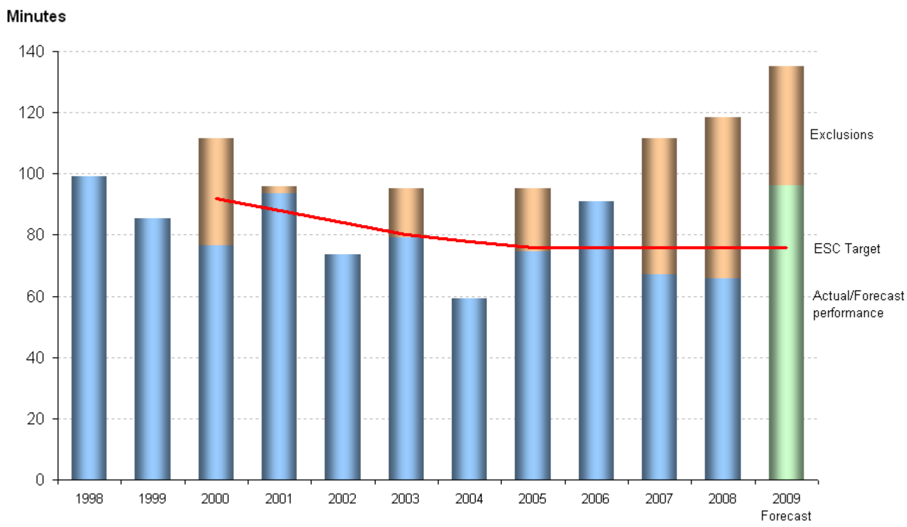
Table 15-1 shows JEN's proposed target service levels included in its original regulatory proposal based on the past four years of historical performance and a forecast for 2009 performance.

Table 15-1: Service performance targets for forthcoming regulatory control period

Service performance measures	Target
Total customer minutes off supply (SAIDI)	89.4
Unplanned customer minutes off supply (SAIDI)	76.3
Planned customer minutes off supply (SAIDI)	13.2
Unplanned sustained interruption frequency (SAIFI)	1.28
Unplanned interruption duration (CAIDI)	60
Momentary interruption frequency event (MAIFIe)	0.94
Calls to fault line answered within 30 seconds	63%

JEN's forecast of reliability performance for 2011-15 is shown in Figure 15-1 below.

Figure 15-1: Unplanned SAIDI (AER exclusion criteria)



Note: The bars coloured in tan represent exclusion events based on AER criteria.

Table 15-2 shows JEN's updated service target performance outcomes for actual 2009 outcomes as advised to the AER on 19 March 2010.

Table 15-2: Updated service performance targets for forthcoming regulatory control period

Service performance measures	Target
Total customer minutes off supply (SAIDI)	90.5
Unplanned customer minutes off supply (SAIDI)	74.6
Planned customer minutes off supply (SAIDI)	15.9
Unplanned sustained interruption frequency (SAIFI)	1.26
Unplanned interruption duration (CAIDI)	59.4
Momentary interruption frequency event (MAIFIe)	0.93
Calls to fault line answered within 30 seconds	63%

15.2 Summary of AER's draft determination and decision

The summary of the AER's draft decision is that:

- The AER accepted JEN's proposal to use average of 2005-2009 actual performance for target setting.

- The AER accepted JEN's proposal for fault call telephone answering target to be set at the average of the most recent two years of historical data.

- The AER proposed to apply the default 5 per cent cap on revenue at risk for JEN.

- The AER rejects the impact of climate change on future performance, with a consequent revision (by the AER) of MAIFIe target.

- No adjustment has been made to future targets even though the AER has rejected significant components of JEN's capex forecast.

- The measurement of MAIFIe in accordance with the ESCV's S factor will be applied for the forthcoming regulatory control period. The AER's reasons are that moving to proposed STPIS would result in significant increases in reported MAIFI and would also discourage DNSP's from adopting "multi-shot" reclose approaches.

- The measurement of MAIFIe in accordance with the ESCV's S factor will continue to use the 1 minute period, and that JEN's proposal to adopt 5 minutes is ignored.

- The AER clarified its definition of fault call telephone answering response.

- It does not appear to acknowledge JEN's amendments to the AER's proposed formula for incorporating the STIPS into annual allowed price movements.

- The AER rejected JEN's calculation of the MED threshold, quoting that it is counterintuitive, undermines the incentive of setting a threshold in the first place, and is arguably inconsistent with the manner in which the AER must make the Victorian determinations. The AER has substituted a threshold of 7.04 SAIDI minutes instead of JEN's proposed threshold of 6.62 SAIDI minutes.

- The AER has developed a methodology to close out and reconcile the ESCV's S factor scheme when it is withdrawn. This will include a reconciliation in the 2016-2020 decision to account for 2010's actual performance.

- It does not accept JEN's reliability, appointment and connection GSL forecasts which are based on data from January 2008 to July 2009.

- It does not accept JEN's application of the AER's MED exclusion criterion to the 2009 data for forecast of reliability GSL.

- It does not accept JEN's forecast GSL payment for street lighting repair which uses average of 2004-2008 data.

- The AER requires JEN to provide telephone answering historic data to allow targets to be set taking into account of STPIS exclusion criteria.

- The AER requests Victorian DNSPs to resubmit fault call centre targets applying actual number of calls abandoned within 30 seconds.

15.3 JEN's response to AER's draft determination and decision

15.3.1 AER's view that DNSP's will 'sweat' assets

JEN notes that the Victorian DNSPs have been subject to both a GSL scheme and an S factor scheme that discourages deferred expenditure. If a DNSP attempted to make cost efficiencies at the expense of long-term service levels, JEN believes that it would:

- not be acting prudently in accordance with clause 6.5.7(c)(2) of the Rules

- not be complying with Requirement 3.1 of the Electricity Distribution Code

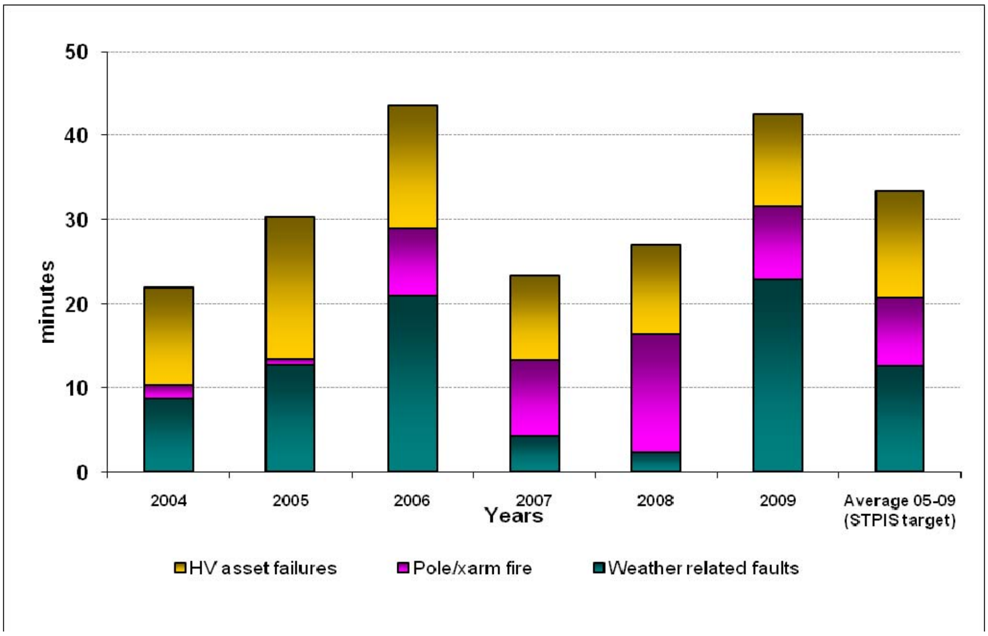
- simply be building a liability for itself that would become more apparent at each price review. If anything, a key impact on long-term service levels will be the ESCV's less-than-forecast allowances and the AER's proposed less-than-forecast draft decision.

15.3.2 Failure to consider climate change impacts

JEN is concerned that the AER has not accepted climate change impacts, particularly more violent and frequent wind and lightning storms. Whilst JEN has incorporated the AER's view that climate change will be gradual in its 2009 base year opex, it 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.

Analysis of outage causes from 2004 to 2009 has revealed that "weather related faults", "pole/crossarm fires" and "high voltage asset failures" contributed to significant variability of the annual reliability performance. Figure 15-2: SAIDI impact by outages cause between 2004 and 2009 shows the SAIDI impact of the three outages causes between 2004 and 2009:

Figure 15-2: SAIDI impact by outages cause between 2004 and 2009

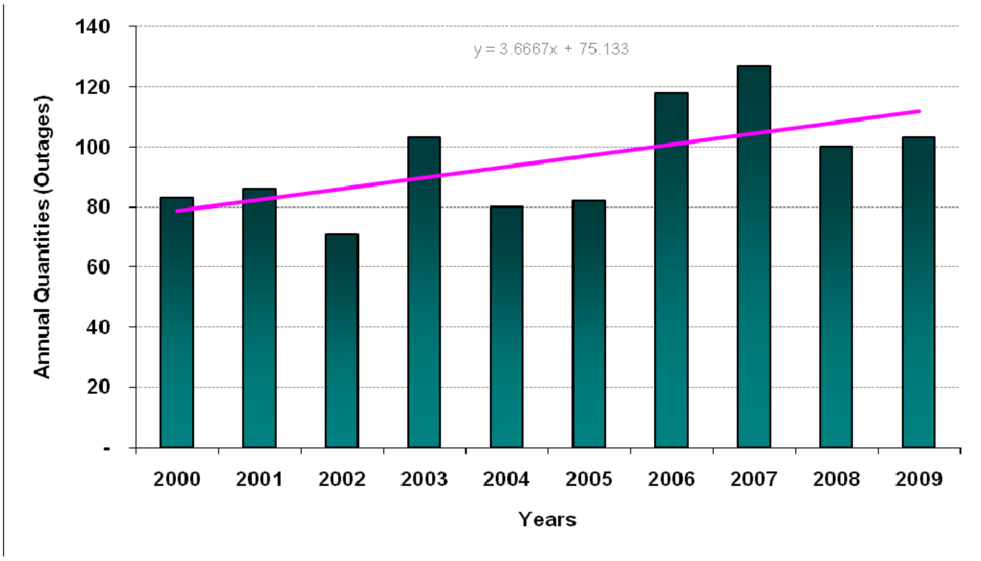


JEN has also shown in the graph average SAIDI impact (2005 to 2009) from the 3 causes based on the principle adopted for STPIS target setting. It can be seen that STPIS targets, based on average performance, will be challenging to meet if violent weather events become more frequent such as what have been experienced in 2006 and 2009.

What is not apparent from the above graph is the 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, as shown in Figure 15-3. Whilst this increase is apparent in the numbers of failures, it is not yet apparent in SAIDI as presented earlier. There is no obvious increasing trend of SAIDI relating to asset failure with the average contribution to the JEN SAIDI being 13 minutes per annum over 2005-9 regulatory control period.

The discrepancy between the increases in asset failure volumes without a corresponding increase in SAIDI can only be attributed to one reason. Over recent years, JEN has predominantly been addressing the symptoms of asset failure rather than the underlying causes with the installation of recloser equipment and remote controlled switchgear to increase switching flexibility, reducing the numbers of customers affected as well as the duration of the outages for asset related failure. This has masked the underlying issue with increasing asset failures.

Figure 15-3: High voltage equipment failure resulting in feeder and automatic circuit recloser outages



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.

15.3.3 Rejection of proposed 5 minute period

Whilst JEN appreciates the need to maintain consistency (which is understood to be a factor in the AER deciding to retain the ESCV's MAIFI definition), JEN is none-the-less disappointed that its reasoning for a 5 minute period has been ignored and, by implication, rejected.

JEN would also appreciate the opportunity to discuss the apparent inconsistency of, on the one hand, the AER wishing to propose an alternative mechanism and, on the other hand, a DNSP's proposal to adopt an alternative approach (especially that would align with internationally accepted standards) being ignored.

15.3.4 Calculation of major event day threshold

In section 15.7.5 of its draft decision, the AER set out its considerations with regard to the setting of the Major Event day threshold.

The AER's interpretation is to only exclude items under clause 3.3(a) of the STPIS scheme, but not those under clause 3.3(b). The STPIS scheme clearly states that any exclusions permitted under clause 3.3 and 5.4 of the *scheme* are reflected in the major event day boundary calculation. The AER's interpretation is therefore clearly in conflict with its STPIS scheme.

JEN notes that in the AER's final STPIS scheme decision[454] there were stakeholder comments from Ergon Energy, EnergyAustralia and JEN around this aspect and the confusing nature of the text.

The AER did not consider these suggestions in the redrafting of the November 2009 STPIS leaving the document wording inconsistent with the AER intent as described in its draft decision.

JEN believes that it understands the AER's interpretation and in general supports the AER's intent of the scheme. However, the non inclusion of the exclusions under clause 3.3(b) is clearly at odds with how the STPIS scheme is currently documented. JEN believes that this inconsistency between the AER intent and the STPIS scheme can be readily addressed by ensuring that only clause 3.3(a) and not clause 3.3 is referred to throughout the text when reference is made to Major Event day threshold calculations. Otherwise, JEN believes that the JEN interpretation is clearly based on the November 2009 "Electricity distribution network service providers Service target performance incentive scheme" and should be adopted.

15.3.2.3 Guaranteed service levels

In May 2010, the AER requested the ESCV to amend the Distribution Code to allow the application of the national GSL scheme for the 2011-2015 regulatory control period.

JEN favours national regulatory reform and therefore accepts the AER's draft decision. However, the current JEN approach for advising of planned outages by mail-box drops without keeping records is inadequate for this new GSL and therefore JEN will need to develop IT system in order to keep records of customer notification to demonstrate compliance with this requirement. The cost for the development of IT system will need to be funded.

15.4 Revised STPIS

Consistent with the AER's STPIS, JEN's opex and capex forecasts have been designed to maintain reliability performance at the current five year average historical level. They have also been designed to deliver improved customer

454 AER, *Final decision, Electricity distribution network service providers Service target performance incentive scheme*, November 2009.

service during major emergency events and continue to foster a positive customer service business culture.

Table 15-3 summarises the key features of JEN's revised STPIS.

Table 15-3: Key features of JEN's revised STPIS

JEN's original regulatory proposal	Comments/JEN's revised proposal
That the ESCV's definition of MAIFI continues to be used	The AER accepted JEN's proposed MAIFI definition JEN has incorporated the AER's draft decision
That the MAIFI event duration be amended from 1 minute to 5 minutes	The AER rejected the proposal on basis that ESCV definition should continue to apply[455] JEN has incorporated the AER's draft decision
Adjustment to forecast MAIFI targets due to climate change (JEN EDPR MAIFI adjustment to baseline target, Confidential, 30 March 2010)	The AER is not convinced that the AECOM reports can be accurately relied upon for predicting that 2011–15 will have more hot and windy days than 2005–2009. Hence, the AER considers that JEN did not provide sufficient justification for an adjustment to its MAIFI target[456] JEN has incorporated AER's draft decision
Correction to proposed formula for incorporating STPIS into annual allowed price movements.	Not considered by the AER in its draft decision. JEN requests that the AER provides a comprehensive specification for how the 'S_t' parameter in the price control for standard control distribution services will be calculated for each year of the next regulatory period

455 Draft decision, p. 670.

456 Draft decision, p. 672.

JEN's original regulatory proposal	Comments/JEN's revised proposal
That the T_{MED} be fixed for the entire period.	JEN prefers to have a constant threshold for regulatory certainty, which would assist in achievement of STPIS objectives by allowing DNSPs to make better medium term plans However, JEN acknowledges that AER prefers T_{MED} to vary over time to reflect up to date outage information and has incorporated this view into its revised submission
Proposed to close out the ESCV's S factor payments through an adjustment to the opex building block as foreshadowed in the AER's Framework and approach paper[457]	JEN has incorporated the AER's draft decision for S factor true-up within the building block cost of services JEN requests that the AER reconsider its proposed treatment of adjustments for actual 2010 performance as set out in section 4.3.1 of this revised regulatory proposal
The literal interpretation of the T_{MED} calculation	The AER has decided that double application of MED threshold is not valid and as a result, T_{MED} should be 7.04 rather than 6.62[458] JEN understands the AER's interpretation and in general supports this position as reflective of the intent of the scheme as well as being consistent with IEEE1366 upon which it is based. However, this interpretation is clearly at odds with the STPIS schemen decision. JEN requests the AER to amend the STPIS scheme to more clearly reflect IEEE 1366
Continue to advise planned outages by mail-box drop that does not provide for confirmation of receipt based on the ESCV GSL framework	JEN accepts the AER's draft decision provided that the AER allows for the required additional capex for a mailing system to ensure JEN can keep records of customer notifications in order to demonstrate compliance with this requirement.
S factor true-up in 2012 to account for 2010 actual performance	The AER accepted JEN's proposal

[457] AER, *Framework and Approach*, May 2009, p. 203.

[458] Draft decision, p. 657.

JEN’s original regulatory proposal	Comments/JEN’s revised proposal
Telephone answering target to be set at the average of the most recent two years of historical data	The AER accepted JEN’s proposal. JEN notes that the measure becomes more focused on the performance of human response to fault calls, rather than the performance of the IVR as the current measure does JEN has incorporated the AER’s draft decision
Guaranteed Service Levels based on the current Victorian ESCV scheme	JEN accepts the application of the national GSL scheme for the 2011-2015 regulatory control period upon amendment to the Victorian Electricity Distribution Code. JEN will consult with the AER on target setting when the national GSL scheme is to be applied.
2010 reliability forecasts based on JEN’s internal forecast of performance	2010 reliability forecasts based on 2006-2009 average performance

15.4.1 MAIFI event duration amendment

While JEN believes that a 5-minute definition should be applied for MAIFI event duration to align with Institute of Electrical and Electronics Engineers (**IEEE**) standard and to encourage development of self-healing networks for the benefit of customers, JEN has incorporated the AER’s draft decision in the revised proposal.

15.4.2 Adjustment to forecast targets due to climate change

JEN has incorporated AER’s draft decision in the revised proposal.

15.4.3 Migration from Victorian to national framework

In May 2010, the AER requested the ESCV to amend the Electricity Distribution Code to allow the application of the national GSL scheme for the 2011-2015 regulatory control period.

The AER is seeking views from the Victorian DBs on any matters that may impact the ESCV’s decision to amend clause 6 of the Electricity Distribution Code. Depending on those views, the ESCV will determine whether it is required to undertake broader public consultation, which will need to commence with an Issues Paper by 30 June 2010.

The Victorian scheme is very similar to the national scheme except that:

- there is no GSL payment requirement for failure to provide notice of planned interruptions
- there is no GSL payment requirement for duration of interruptions (as distinct from total duration of interruptions)
- the Victorian DBs must make GSL payment for exceeding the threshold for momentary interruptions.

JEN favours national regulatory reform; however, JEN has the following issues in moving the GSL framework into a national scheme:

1. the AER considers that it is appropriate to apply the GSL in the forthcoming regulatory control period. JEN is expected to maintain adequate records to show that it is compliant with this regulatory obligation:
    a. JEN currently notifies customers of planned interruptions via manual card drops in letter boxes, dropped by JEN's staff or a contractor depending on the nature of the job
    b. JEN does not keep records as to whether individual customers have been notified, however it keeps maps of area notified. In its proposal, JEN stated that the costs of adding this GSL requirement are likely to outweigh the benefits
2. each year approximately 11,000 customers are notified of planned interruptions. JEN reported full compliance to the AER on the basis of its processes, despite receiving approximately 50 complaints each year from customers claiming they have not been notified
3. it will be difficult to prove that customers have been notified with card dropping in letter boxes. Dissatisfied customers may take their entitlements to GSL payments to the Ombudsman resulting in further costs to JEN. JEN can expect to incur additional costs in relation to processing complaints and GSL payments.

15.4.4 JEN's revised STPIS targets

Table 15-4 shows JEN's updated service performance targets based on average of 2005 to 2009 performance outcomes and a single application of the 2.5 beta method in T_{MED} calculation.

Table 15-4: Updated service performance targets for forthcoming regulatory control period

Service performance measures	Target
Total customer minutes off supply (SAIDI)	90.5
Unplanned customer minutes off supply (SAIDI)	77.42
Planned customer minutes off supply (SAIDI)	15.9
Unplanned sustained interruption frequency (SAIFI)	1.28
Unplanned interruption duration (CAIDI)	60
Momentary interruption frequency event (MAIFIe)	0.895
Calls to fault line answered within 30 seconds	57.46%

Table 15-5: Updated GSL payment targets for forthcoming regulatory control period (based on ESCV GSL scheme)

GSL parameter	Forecast number (p.a.)	Forecast payment (p.a.)
15 minutes late for appointment	6	112
Connections not made on agreed date – 1-4 days delay	25	2,650
Connections not made on agreed date – 5+ days delay	3	1,090
20 hours of interruption	141	14,050
30 hours of interruption	3	375
60 hours of interruption	-	75
Not repairing street lights within 2 days	54	540

16 Pass through events

Consistent with the underlying purpose and objectives of distribution pass through provisions[459], JEN continues to nominate identifiable pass through events that are beyond its control, not clearly covered by other pass through event categories, and represent an efficient allocation of risk.

JEN considers that the AER's draft decision in relation to some of JEN's nominated pass through events is in error for the reasons set out below, each of which potentially undermines the objectives of the Rules:

- Some events nominated by JEN have been rejected by the AER on the basis that they are potentially covered by other event categories. In several areas, notably *force majeure events* and *ETS events*, this is unclear (with any potential overlap being open to differing interpretations and therefore exposing JEN to a risk that the events are left uncovered if the nominated event is not accepted by the AER) and / or incorrect. For clarification, the AER should either confirm that the nominated events fall within the scope of other events (and therefore remove the potential risk that the event if left uncovered if the AER does not accept the relevant nominated pass through event), amend its proposed definitions to clarify inclusion, or treat the events as additional nominated pass through events.

- The AER's views on JEN's proposed asbestos compensation event is inconsistent with its recent distribution determinations in New South Wales.[460] The AER should include an *asbestos compensation event* as a nominated pass through event. The AER should not distinguish between publicly and privately owned DNSPs as proposed, nor draw direct parallels between businesses generally, and regulated DNSPs.

- The AER has not considered whether clause 6.21.2 of the Rules provides JEN with appropriate protection in the event of a financial failure of a retailer and has overlooked the impact of the ESCV's decision on credit support arrangements. JEN submits that the AER should include the financial failure of a retailer as a nominated pass through event. Alternatively, the AER should amend the credit support arrangements under the default Use of System Agreement to give Victorian distributors full credit support.

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[459] See the AEMC's *Rules Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18*, 16 November 2006, pp 104-05, which stated that the objective of pass through provisions in distribution and transmission are the same.

[460] *AER, New South Wales Distribution Determination 2009-2014, Final decision*, p. 278, as quoted at p. 719 of the AER's draft decision

- It is beyond the AER's power to determine a materiality threshold for JEN's pass through events within a distribution determination.

- While the AER and its experts have recognised that the Royal Commission's recommendations will impact upon DNSPs, the AER has not accepted the bushfire event proposed by Powercor. JEN submits that the AER should include recommendations arising from the Royal Commission into the Victorian Bushfires as a nominated pass through event, to the extent that recommendations result in new obligations.

In addition, JEN considers that the AER has erred in adopting a narrow definition of a 'regulatory change event'. A 'regulatory change event' should not be confined to changes in *existing* regulatory obligations, but should include the removal of an existing regulatory obligation, a change in an existing regulatory obligation and the imposition of a new regulatory obligation.

JEN has also proposed additional nominated pass through events for Transmission Connection, Avoided TUoS, and Inter DB Charges and Revenues in response to the AER's draft decision on the ability of the DNSPs to recover costs associated with these activities under the Rules.

16.1 Summary of JEN's original regulatory proposal

In addition to those listed in the Rules, JEN proposed the following pass through events in its original regulatory proposal:

- emissions trading scheme (**ETS**) event
- financial failure of a retailer event
- declared retailer of last resort (**ROLR**) event
- insurer credit risk event
- insurance event
- asbestos compensation event
- force majeure event.

JEN proposed a materiality threshold of $1 million for each of these pass through events. This threshold would apply to a single event or to a number of incremental events in the same pass through category occurring in the same regulatory year.

This was proposed to operate as a symmetrical materiality threshold applicable to both positive and negative change events for events that are subject to such a threshold.

JEN proposed to retain the existing arrangements under the ESCV's final determination for the materiality thresholds for existing pass through events which are financial failure of a retailer and declared RoLR event.

16.2 Summary of AER's draft determination and decision

In addition to the four pass through events defined in Chapter 10 of the Rules (a regulatory change event, a service standard event, a tax change event and a terrorism event), in the draft decision the AER proposed to include in the distribution determinations the following nominated pass through events for the 2011-2015 regulatory control period for the Victorian DNSPs, in accordance with clause 6.12.1(14) of the Rules:

- a declared retailer of last resort event
- insurer credit risk event
- an insurance event
- a natural disaster event.

In proposing to include the above nominated pass through events in the distribution determinations, the AER purported to set a materiality threshold for all Victorian DNSPs of one per cent of the smoothed forecast revenue in each of the years of the regulatory control period.

The AER rejected the following specified pass through events proposed by JEN:

- force majeure event, asserting that such events will likely be captured in the 'natural disaster' event accepted by the AER as a pass through event
- financial failure of a retailer event, asserting that the appropriate method to mitigate against the risk of such an event is through the prudential requirements contained in clause 6.21.1 of the Rules
- an asbestos compensation event, asserting that asbestos risk is faced by all businesses in the market, and it is the responsibility of the purchaser of a business to undertake any due diligence. Any consequent risk should be borne by shareholders, not consumers.

Relevantly to JEN's revised proposal, the AER also rejected the bushfire event proposed by Powercor.

16.3 JEN's response to AER's draft determination and decision

In assessing JEN's cost pass through proposal, JEN believes that in its draft decision the AER has:

- incorrectly assumed it has the ability to set a materiality threshold for pass through events in a distribution determination
- rejected JEN's proposed force majeure event on the basis that it is likely that these events will be captured by the AER's preferred nominated natural disaster, even though the natural disaster event as currently defined does not capture all of the events that would fall within JEN's proposed force majeure event
- rejected JEN's proposed financial failure of a retailer event:
  - on a basis inconsistent with its recent South Australian distribution determination
  - without consideration as to whether clause 6.21.2 of the Rules provides appropriate protection. In particular, overlooking the impact of the decision of the ESCV's on credit support arrangements which currently restricts the amount of credit support that JEN may require from a retailer.
- rejected the asbestos compensation without a sound basis and on a basis inconsistent with its comments and treatment of New South Wales DNSPs.

16.3.1 Materiality threshold

In its draft decision, the AER purported to determine that the appropriate materiality threshold for all pass through events for the Victorian DNSPs is one per cent of the smoothed forecast revenue in each of the years of the regulatory control period.[461] JEN considers that it is beyond the AER's power to set a materiality threshold and that even if the AER had the ability to do so, the proposed threshold does not promote efficient network services. JEN submits that, it is inappropriate to set a materiality threshold at a level that is higher than the level at which the AER considers individual cost of service items.

[461] Draft decision, p. 715.

Ability of AER to set a materiality threshold for pass through events in a distribution determination

JEN does not consider that it is open to the AER to set a materiality threshold for pass through events in a distribution determination. Specifically, JEN does not consider that the Rules provide the AER with a legal basis for incorporating a specific threshold or formula for determining a materiality threshold for pass through events that is then binding on the AER when it comes to assess any relevant pass through event.

For DNSPs, pass through events comprise those listed in the definition of 'pass through event' in Chapter 10 of the Rules, which includes specific listed events[462] as well as an event nominated in a distribution determination as a pass through event. Clause 6.12.1(14) provides that a distribution determination is predicated, amongst other things, on a decision by the AER on the additional pass through events that are to apply to a DNSP for a regulatory control period. Relevantly, clause 6.12.1 does not provide that a decision on the materiality threshold to apply to pass through events is a constituent decision of a distribution determination.

The only clause in Chapter 6 of the Rules that is relevant to the materiality threshold to apply to pass through events is clause 6.2.8. Pursuant to this clause, the AER may publish guidelines as to, amongst other things, the AER's likely approach to determining materiality in the context of possible pass through events. Clause 6.2.8(c) relevantly provides that guidelines published under clause 6.2.8(a) are not mandatory and therefore do not bind the AER or anyone else. Clause 6.2.8(c) goes on to provide that while the guidelines are not binding, if the AER makes a distribution determination that is not in accordance with a relevant guideline, the AER must state, in its reasons for the distribution determination, the reasons for departing from the guideline.

Therefore, in connection with the materiality threshold to apply to pass through events, the AER may, at most, publish a guideline indicating its approach to determining whether a pass through event is material. The AER does not have the ability to go so far as to set a materiality threshold for pass through events in a distribution determination.

Consistency with the national electricity objective and Rules

JEN also notes that even if the AER had the power to set a materiality threshold (which JEN disputes), JEN believes that its draft decision is inconsistent with the NEO (section 7), section 7A(2) and section 7A(3) of the Rules.

[462] Being: (a) regulatory change event; (b) service standard event; (c) tax change event; and (d) a terrorism event.

Specifically, JEN considers that the AER's materiality threshold is inconsistent with clause 7A(2) of the Rules as the AER's approach to the materiality threshold does not provide service providers generally, or JEN in particular, with a 'reasonable opportunity to recover at least the efficient costs the operator incurs in...providing direct control services'[463] which, in the long term, diminishes a business's ability to continue to efficiently invest in providing electricity services to its customers.

In addition, JEN believes that by adopting a threshold that clearly exceeds the administrative costs associated with assessing cost pass through applications, DNSPs may be incentivised to "over insure" in order to reduce their overall financial risk, which is inconsistent with the requirements of the Rules, particularly clause 7A(3), which requires that businesses be provided with incentives to efficiently provide network services.

Both outcomes are clearly inconsistent with the long term interest of consumers and the NEO which is to:

> promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –
>
> (a) price, quality, safety, reliability and security of supply of electricity and
>
> (b) the reliability, safety and security of the national electricity system.

If the AER believes that it has the power to set a materiality threshold, JEN believes that consistent with clauses 7A(2) and (3) of the Rules the threshold should be set to reflect JEN's administrative costs associated with applying for the cost pass through applications. If JEN believes that its administrative costs are greater than the costs associated with the pass through event, then it will not apply for the pass though event.

16.3.2 Emission trading scheme event

JEN notes that the AER did not accept JEN's proposed ETS event on the basis that it could be an event relating to possible new, changed or removed regulatory obligations that are either already within the scope of a 'regulatory change event' or 'service standard event'.[464]

For clarification, in its final decision, the AER should confirm that the ETS falls within the 'regulatory change event' or 'service standard event' scope. If the AER is unable to do so, JEN requests that the AER treat the ETS event as a nominated pass through event.

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463 Section 7A(2) of the Rules.

464 Draft decision, p. 710.

16.3.3 Force majeure event

In its draft decision the AER has rejected JEN's proposed force majeure event on the basis that such events will likely be captured in the natural disaster event accepted by the AER as a pass through event.[465] JEN maintains that its proposed force majeure event should be included in the AER's determination as it covers events that would otherwise be uncovered by the AER's natural disaster event, including events that may occur before the commencement of the next regulatory control period and activities such as war, riot or sabotage (that would not necessarily be captured by the terrorism pass through event[466]).

Relevantly, JEN proposed the following force majeure event as a pass through event in its original regulatory proposal:

> An event that is outside JEN's reasonable control and for which:
>
> - the occurrence and / or timing is unpredictable;
> - no cost allowance has been made in the distribution determination;
> - insurance is (or has become) unavailable or is only available at a cost that would not be efficient for a prudent distributor; and
> - no other category of pass through event would apply,
>
> as a result of which JEN incurs materially higher or lower costs in providing direct control services than it would have incurred but for that event.[467]

The AER's accepted natural disaster event is defined as follows:

> Any major fire, flood, earthquake, or other natural disaster beyond the control of the DNSP (but excluding those events for which external insurance or self insurance has been included within the DNSP's forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to the DNSP of providing direct control services.

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465 Draft decision, p. 724.

466 The definition of "terrorism event" is as follows: "An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and / or put the public, or any section of the public in fear) and which materially increases the costs to a Transmission Network Service Provider of providing prescribed transmission services or the costs to a Distribution Network Service Provider of providing direct control services".

467 JEN, *Jemena Electricity Networks (Vic) Ltd Regulatory Proposal 2011-15*, 30 November 2009, p 193.

Draft decision, p. 728.

Accordingly, while there is a degree of overlap between the force majeure event proposed by JEN and the AER's natural disaster event, it is not correct that all of the events that would fall within the force majeure event would fall within the natural disaster event. For example:

- the natural disaster event is confined to "natural" events, which is likely to be interpreted as a disaster that was not directly caused by humans – which would appear to exclude events such as war, riot or sabotage, the force majeure event does not have this limitation

- the natural disaster event is confined to events that occur during the forthcoming regulatory control period, the force majeure event does not have this limitation.

In addition, JEN notes that the AER has recently accepted that it is open to a DNSP to nominate an event that may take place before the relevant forthcoming regulatory control period.[468]

16.3.4 Financial failure of a retailer event

The AER has rejected JEN's proposed financial failure of a retailer event on the basis that the appropriate method to mitigate against the risk of such an event is through the prudential requirements contained in clause 6.21.1 of the Rules.[469]. Not only is the AER's draft decision inconsistent with its recent South Australian distribution determination, it also fails to consider whether clause 6.21.2 of the Rules will provide JEN with appropriate protection and overlooks the impact of the decision of the ESCV on credit support arrangements. JEN maintains that the proposed financial failure of a retailer event should be included in the distribution determination, particularly in light of the two retailer failures in Victoria in the past three years.[470]

Consistency with the AER's South Australian distribution determination

JEN submits that the AER's distribution determination for the Victorian DNSPs should be consistent with its recent South Australian distribution determination. Relevantly, in that instance, the AER rejected a similar event proposed by ETSA Utilities on the basis that it did not accept that a retailer failure event is "highly likely to occur over the next regulatory control period, although it is possible."[471] However, in its draft decision the AER has re-considered its position on foreseeability, and now considers that foreseeability should be considered in terms

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[468] AER, *South Australia Distribution Determination 2010-11 to 2014-15*, May 2010, p. 238.

[469] Draft decision, p. 724.

[470] Jackgreen (International) Pty Ltd in December 2009 and Energy One in June 2007.

[471] AER, *South Australia Distribution Determination 2010-11 to 2014-15*, May 2010, p. 237.

of whether the event can be "tightly defined in advance rather than the notion of foreseeability being connected to the probability of the event occurring in a particular period of time."[472]

Notably, in its South Australian distribution determination the AER did not reject the event proposed by ETSA Utilities on the basis that the risk could be address via the prudential requirements in clause 6.21.1 of the Rules. Moreover, in that instance, the AER stated that it considered that if a retailer failure event did occur, it would be open to ETSA Utilities to seek pass through of these costs as a general nominated pass through event.[473] Evidently, the AER has previously considered it appropriate for the costs of such events to be passed through.

JEN notes that the AER has decided not to include a general pass through event for the Victorian DNSPs on the basis that events should be "tightly defined" in advance.[474] However, the event can be defined (financial failure of a retailer event), and has previously been accepted as appropriate by the AER; it should therefore be included as a nominate pass through event for JEN.

The prudential requirements do not provide JEN with appropriate protection

Contrary to the AER's view, the prudential requirements in clause 6.21.1 of the Rules do not provide JEN with appropriate protection as the ESCV's 2006 decision on credit arrangements currently restricts the amount of credit support JEN may require from a retailer under a use of system agreement. The existing credit arrangements do not fully compensate DNSPs for retailer failure as DNSPs are unable to recover the full amount of the outstanding debt. Relevantly, in its 2006 decision, the ESC:

- determined that a retailer would be required to provide credit support to a distributor when the amount of the retailer's average billed and unbilled distribution service charges liability exceeded its credit allowance:
    - the amount of credit support provided by the retailer is calculated as the amount by which the retailer's average billed and unbilled distribution service charges (over a three month period) exceeds the retailer's credit allowance
    - the retailer's credit allowance is calculated as the percentage of the relevant distributor's maximum credit allowance corresponding to its credit rating

472 Draft decision, p. 719.

473 AER, *South Australia Distribution Determination 2010-11 to 2014-15*, May 2010, p. 237.

474 Draft decision, p. 719.

– the distributor's maximum credit allowance is calculated as 33.33% of the distributor's annual distribution service charges revenue for the most recent year reported to the ESC.

In practice, under the ESCV's formula many retailers provide no, or minimal, credit support. For example, JEN incurred a loss of $38,461 with the financial failure of Jackgreen International Ltd in December 2009. Before the financial failure, Jackgreen's credit rating was B+. Under the default Use of System Agreement, Jackgreen was entitled to a credit allowance amount of $1,486,518. JEN's revenue exposure to Jackgreen at the time was $48,041. Given the revenue exposure was less than the credit allowance JEN was not entitled to ask Jackgreen for credit support. The AER subsequently rejected JEN's (and other Victorian distributors') request to pass through the loss it has incurred due to the failure of Jackgreen.

- extended credit allowance to retailers with very low credit ratings (retailers with credit ratings below BBB- are given a credit allowance). As a result, a retailer could incur a sizeable amount of debt before a distributor could ask for credit support, at which time the retailer may be financially distressed and unable to provide the requested support.

  For example, a retailer with a filed bankruptcy petition and a credit rating of C could still have access to a credit allowance of 0.033 per cent of the annual distribution service charges revenue.[475] If the distributor's annual distribution service charges revenue is $100M, this equates to an unsecured credit allowance of $33,000 to a business that is an extreme credit risk.[476] Also, in the Jackgreen example above, theoretically, JEN's loss could have been up to $1.4M, as no credit support could be required of Jackgreen until JEN's revenue exposure exceeded $1,486,518.

The ESCV recognised the increased risk of this approach for distributors. It implemented its credit support arrangements on the basis that it would allow distributors to pass through any costs incurred as a result of the distributor having inadequate security in the event of a retailer insolvency (that is, the distributor could recover the difference between the credit support and actual loss directly through a pass through mechanism). Similarly, JEN's proposed financial failure of a retailer event would apply to uncovered charges in excess of the amount of credit support held by JEN for that retailer. JEN submits that the AER should acknowledge the increased risk associated with the ESCV's credit support arrangements and allow the costs of such events to be passed through.

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[475] The percentage of distributor's maximum credit allowance for a retailer with a credit rating of C is 0.1. Accordingly, the retailer's credit allowance would be calculated as 0.1 x 33.33% =0.033% of annual distribution service charges revenue.

[476] Citipower/Powercor, Letter to ESCV, 18 August 2006, in respect of ESCV credit decision.

Relevantly, in its report, prepared for the ESCV in relation to the review of credit support arrangements, the Allen Consulting Group states as follows:

> In the Electricity Distribution Price Review 2006-2010 the Commission decided to separate the credit hurdle that is imposed on electricity retailer from the credit risk that is borne by the distributors. This was done by introducing a mechanism for distributors to potentially pass through to customers the net financial consequence associated with retailer default. Under this proposal electricity distributors that respond quickly will ultimately be able to recover residual losses from the end customer. In other words, the residual credit risk is transferred from the distributor to the end customer. The pass through arrangements therefore isolate the distributor from the long run financial consequences of a retailer failing. This both protects the distributor and mitigates the security of supply concerns, or systemic risk that the credit arrangement also protect against.[477]

DNSPs are also exposed to risks in the event of a retailer default. In these circumstances, a DNSP cannot simply cease supply. The distribution use of service debt continues to accumulate until the retailer rectifies the default or customers are transferred to another retailer under commercial arrangements or by use of the Retailer of Last Resort (**RoLR**) mechanism. The Use of System Agreement sets out the procedures required to terminate the agreement. The value at risk of this process can range between 84 to 116 days of distribution use of service charges.

JEN notes that the consideration of whether a DNSP has taken appropriate action to mitigate the harm arising from a pass through event (which may include having prudential requirements in place) is built into the AER's assessment of the relevant costs that may be passed through. Therefore, a DNSP is incentivised to rely upon clause 6.21.1 to have appropriate prudential arrangements in place; however to the extent the DNSP is still exposed to a risk, this should be addressed via a pass through event.

16.3.5 Asbestos compensation event

In rejecting JEN's proposed asbestos compensation event, the AER asserted that this is a risk faced by all businesses in the market; it is the responsibility of the purchaser of a business to undertake any due diligence; and that any consequent risk should be borne by shareholders, not consumers.

The AER's position appears to be in direct conflict with its comments and rationale set out in its New South Wales distribution determination. In that instance, the AER accepted that liability claims in relation to asbestos and electric magnetic fields were examples of "events occurring during a regulatory control period that

477 The Allen Consulting Group, *Retailer DUoS credit support arrangements, Implementation issues in Victoria*, June 2006, p. 10.

are uncontrollable, unforseen, and have a material impact on costs". Relevantly, the AER stated that it:

> "…recognises the possibility of events occurring during a regulatory control period that are uncontrollable, unforeseen, and have a material impact on costs. Examples of such an event include a major natural disaster such as a bushfire or earthquake, and liability for claims relating to asbestos or electric and magnetic fields. In these situations, although the occurrence of the event may be a possibility, its occurrence is unforeseen in that the event is not expected to occur during the forthcoming regulatory control period."[478]

JEN submits that all DNSPs should be treated equally – it is unclear why the AER considers that it would be appropriate to treat the Victorian DNSPs differently from the New South Wales DNSPs. To the extent that the AER considered that it would be appropriate for the New South Wales DNSPs to be able to pass through costs to consumers for claims relating to, amongst other things, asbestos, the Victorian DNSPs should be treated in a similar way.

The relevance of the AER's stated reason for rejecting the asbestos compensation event (that it is a risk faced by all businesses) is unclear. Arguably, a number of pass through events are faced by a range of different businesses. For example, a range of businesses would face a risk of their costs increasing as a consequence of events such as those specified in the Rules, including tax change events and terrorism events. In this regard the AER has misdirected itself – the question is not whether a particular risk is one that is faced by businesses generally, the correct question is, whether permitting pass through of costs associated with a particular event is consistent with the NEO and the revenue and pricing principles. JEN considers that allowing for the pass through of costs associated with an asbestos compensation event is consistent with the NEO and the revenue and pricing principles. The AER has recognised that the pass through of these costs to consumers is appropriate in the distribution determination it made applying to the New South Wales DNSPs.

16.3.6 Insurance event

In the draft decision the AER accepted the insurance event proposed by JEN, but with modifications.[479] The AER's draft decision does not provide the reasons for the making of the decision to modify the insurance event as proposed by JEN or why the AER has withheld its approval of the insurance event as drafted by JEN.

The AER inserted the following exclusion in the insurance event as drafted by JEN:

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[478] Draft decision, p. 719 and AER, *New South Wales Distribution determination 2009–2014, Final decision*, p. 278.

[479] Draft decision, pp. 727-8.

> "This event excludes all costs incurred beyond an insurance cap that are due to the DNSP's negligence, fault, lack of care. This also excludes all liability arising from the DNSP's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by the DNSP."[480]

The exclusions inserted into the drafting of the insurance event, to a significant extent, neutralises or reduces the effectiveness of the cost pass-through event proposed by JEN. Matters such as conduct involving negligence, fault, lack of care are motivators for taking out insurance. The meaning of the phrase "actions or conducted expected or intended by the DNSP" is unclear.

JEN acknowledges the AER's concerns in terms of providing service providers with an appropriate incentive to mitigate and minimise the costs arising in connection with any pass through event. The mere fact that service providers may pass through costs should not provide service providers with an incentive not to operate in a prudent and efficient manner. However, JEN notes that the consideration of whether a DNSP has taken appropriate action to mitigate the harm arising from a pass through event is appropriately built into the AER's assessment of the relevant costs that may be passed through (see clause 6.6.1(j) of the Rules). Therefore, a DNSP is incentivised to minimise the costs incurred beyond an insurance cap. JEN maintains that the drafting of the insurance event in its proposal is appropriate and the AER has not provided any reasons as to why JEN's drafting should not be adopted.

16.3.7 Other areas of concern

Definition of regulatory change event

JEN considers that the AER has erred in moving to a narrow definition of a 'regulatory change event' pass through event that is confined to changes in existing regulatory obligations. In order to be consistent with the NEL objective and purpose of the distribution pass through provisions, the definition should encompass any changes in regulatory obligations during the regulatory control period, including the removal of or changes to existing regulatory obligations, and the imposition of new regulatory obligations.

The literal interpretation adopted by the AER would affect positive and negative pass through events, to the detriment of customers and DNSPs.

Bushfire event

JEN notes the AER's draft decision to reject Powercor's proposed 'bushfire event.'

[480] Draft decision, pp 727 – 728.

Given that the Royal Commission has not yet made its recommendations following its inquiry in the Victorian Bushfires, it is not clear what form those recommendations will take and what steps the DNSPs will be required to take as a result of those recommendations. Therefore, it is not clear whether the recommendations arising from the Royal Commission will fall within a 'regulatory change event' or 'service standard event'. However, it is likely that the recommendations will have a material cost impact on Victorian DNSPs.

Throughout its draft decision the AER has recognised the likely increased activities required by the DNSPs.[481] This was also recognised by Nuttall in its review of the capex and opex forecasts. However, the AER has failed to give the DNSPs any certainty that they will be able to recover the costs of activities undertaken in response to those recommendations through the pass through mechanism.

Instead the AER has rejected Powercor's proposed 'bushfire event' on the basis that it could be an event relating to possible new, changed or removed regulatory obligations that are either already within the scope of a 'regulatory change event' or 'service standard event'.[482]

However, as noted above, the AER's narrow definition of a 'regulatory change event' being confined to changes in existing regulatory obligations creates increased uncertainty as to whether a 'bushfire event' will in fact be an event relating to possible new, changed or removed regulatory obligations that are either already within the scope of the 'regulatory change event'.

JEN believes that it is appropriate for the DNSPs to be able to recover the costs resulting from the recommendations of the Royal Commission. Consistent with the purpose of the pass through provisions, Victorian DNSPs should not be required to bear the burden of the costs of those events. A pass through for recommendations arising from the Royal Commission is consistent with the requirements of the NEL and Rules and should be accepted by the AER. Moreover, it satisfies the AER's criteria for a nominated pass through event. On this basis, the AER should confirm in its final decision that Powercor's proposed 'bushfire event' falls within the 'regulatory change event' or 'service standard event' scope. If the AER is unable to do so, the AER should treat the 'bushfire event' as a nominated pass through event.

[481] AER, Victorian electricity distribution network service providers: *Distribution determination 2011–2015 June 2010 (draft determination)*, pVIII, p273, p292 and p913.

[482] Draft decision, p 710.

16.4 JEN's revised regulatory proposal

In addition to the pass through events accepted by the AER in its draft decision, and in addition to those listed in the Rules, JEN proposes the following pass through events for its distribution determination:

- a force majeure event
- a financial failure of retailer event
- an asbestos compensation event.

In addition, JEN submits that the AER should confirm that its proposed 'ETS event' and Powercor's proposed 'bushfire event' falls within the 'regulatory change event' or 'service standard event' scope. If the AER is unable to provide such confirmation, JEN requests that the AER treat both events as nominated pass through events.

As to a materiality threshold, JEN submits that the AER does not have the ability to set a materiality threshold for a distribution determination. Even if the AER believes that it does have the ability to do so, JEN submits that the materiality threshold should be set to reflect the administrative costs associated with assessing cost pass through applications, consistent with the NEO (section 7), and sections 7A(2) and 7A(3) of the Rules.

Table 16-1 identifies JEN's proposed pass through events which are in addition to those accepted by the AER in its draft decision. JEN has assessed the circumstances in which each of the proposed pass through events is likely to arise and considers that the probability of these events occurring and/or the impact that these events may have on JEN's costs is too uncertain to reasonably forecast in JEN's forecast revenue requirement. It is therefore appropriate to manage the risks associated with those events by allowing JEN to recover (or requiring it to repay) any material changes in costs by way of a pass through if, and only if, the relevant event occurs.

Table 16-1: Additional proposed pass through events

Item	Status of draft decision	JEN revised regulatory proposal
Force majeure event	AER has rejected JEN's proposed force majeure event on the basis that such events will likely be captured by the AER's proposed natural disaster event. However, as noted in	An event that is outside JEN's reasonable control and for which: • the occurrence and/or timing is unpredictable • no cost allowance has been made in the distribution determination • insurance is (or has become)

Item	Status of draft decision	JEN revised regulatory proposal
	section 16.3.3 not all of the events proposed by JEN are captured by the AER's natural disaster event.	unavailable or is only available at a cost that would not be efficient for a prudent distributor • no other category of pass through event would apply, as a result of which JEN incurs materially higher or lower costs in providing direct control services than it would have incurred but for that event. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.
Financial failure of a retailer event	Rejected by the AER on basis that mitigation is available through the prudential requirements of clause 6.21.1 of the Rules. However, JEN disagrees with the AER and requests the AER to reconsider JEN's nominated 'financial failure of a retailer event'.	The liquidation or administration of a retailer, as a consequence of which JEN does not receive revenue to which it was otherwise entitled for the provision of direct control services. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.
Asbestos compensation event	Rejected by the AER on a basis inconsistent with its decision in the New South Wales distribution determination. Therefore, JEN resubmits the event.	A successful claim for compensation made against JEN for damages resulting from exposure to asbestos on JEN's property. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative

Item	Status of draft decision	JEN revised regulatory proposal
		costs of applying for the pass through event are less than costs incurred.
ETS event	AER rejected on basis that it could be an event relating to possible new, changed or removed regulatory obligations that are either already within the scope of the 'regulatory change event' or 'service standard event'.	In its final decision the AER should confirm that the ETS falls within the 'regulatory change event' or 'service standard event' scope. If the AER is unable to do so, the AER should treat the ETS event as a nominated pass through event as per its original regulatory proposal. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.
Bushfire event	Proposed by Powercor and rejected by the AER	In its final decision the AER should confirm that the 'bushfire event' falls within the 'regulatory change event' or 'service standard event' scope. If the AER is unable to do so, the AER should treat the 'bushfire event' as a nominated pass through event as per its original regulatory proposal. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.

Table 16-2 identifies the proposed pass through events accepted by the AER in its draft decision, with or without modification. While JEN is pleased that the AER has accepted these proposed pass through events, it has proposed:

- a revised materiality threshold to apply in the event the AER is of the view that it has the ability to set a materiality threshold (which JEN disputes)

- that JEN's original definition of 'insurance event' be adopted.

Table 16-2: AER accepted pass through events

Item	Status of draft decision	JEN revised regulatory proposal
Declared retailer of last resort (ROLR) event	JEN proposal accepted by AER but with slightly different definition.	A declared retailer of last resort event means the occurrence of an event whereby an existing retailer is unable to continue to supply electricity to its customers and those customers are transferred to the declared retailer of last resort, and which: (a) falls within no other category of pass through event (b) materially increases the costs of providing direct control services.
	Materiality Threshold The materiality threshold has been set to 1% of annual revenue per event in the year incurred.	*Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.
Insurer credit risk event	JEN proposal accepted by AER.	An event where the insolvency of the nominated insurers of the DNSP, as a result of which the DNSP: a) incurs materially higher or lower costs for insurance premiums than those allowed for in the distribution determination; or b) in respect of a claim for a risk that would have been insured by DNSP's insurers, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy
	Materiality Threshold The materiality threshold has been set to 1% of annual revenue per event in the year incurred.	*Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.
Insurance event	JEN proposal accepted by AER but with modifications as the AER's definition includes	An event that would be covered by an insurance policy but for the amount that materially exceeds the policy limit, and as a result the DNSP must bear the

Item	Status of draft decision	JEN revised regulatory proposal
	"exclusions". *Materiality Threshold* The materiality threshold has been set to 1% of annual revenue per event in the year incurred.	amount of that excess loss. For the purposes of this pass through event, the relevant policy limit is the greater of the actual limit from time to time and the limit under the DNSP's insurance cover at the time of making this regulatory proposal. This event excludes all costs incurred beyond an insurance cap that are due to the DNSP's negligence, fault, lack of care. This also excludes all liability arising from the DNSP's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by the DNSP. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.
Natural disaster event	Proposed by the AER in lieu of JEN's proposed force majeure event. *Materiality Threshold* The materiality threshold has been set to 1% of annual revenue per event in the year incurred.	Any major fire, flood, earthquake, or other natural disaster beyond the control of the DNSP (but excluding those events for which external insurance or self insurance has been included within the DNSP's forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to the DNSP of providing direct control services. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.

16.4.1 Additional nominated pass through events

As set out in section 4.2.5, JEN notes that in its draft decision the AER has raised concerns ability the ability of the DNSPs to recover costs associated with Transmission Connection, Avoided TUoS, Inter DB Charges and Revenues, and

Payments under the PFiT scheme under the Rules. JEN notes the AEMC's rule change in relation to feed-in-tariff schemes that took effect from 1 July 2010, which provides for payments Electricity Industry Amendment (Premium Solar Feed in Tariff) Act 2009 (Vic) to be dealt with through the pricing proposal process.

If the AER considers that the DNSPs are unable to recover costs under the Rules associated with Transmission Connection, Avoided TUoS, and Inter DB Charges and Revenues, then JEN requests the AER to include them as additional nominated pass through events. Table 16-3 sets out JEN proposed pass through events in the event that the AER forms this view in its final determination.

Table 16-3: Additional pass through events

Item	Status of draft decision	JEN revised regulatory proposal
Transmission Services	Not considered but in response to AER concerns over ability for JEN to recover under the Rules	Costs for transmission services (other than transmission use of system services) An event where the DNSP incurs charges associated with the provision of transmission services (other than transmission use of system services) where those transmission services are inputs to the provision of standard control services and for which provision has not otherwise been made for the recovery of these charges from customers. For this event, the terms "transmission services" and "transmission use of system services" are as defined in the Rules. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.
Avoided Customer TUoS charges	Not considered but in response to AER concerns over ability for JEN to recover under the Rules	Costs for avoided Customer TUoS charges An event where the DNSP incurs avoided Customer TUoS charges where those charges are inputs to the provision of standard control services and for which provision has not otherwise been made for the recovery of these charges from customers. For this event, the term "avoided Customer TUoS charges" is as defined in the Rules. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.

Item	Status of draft decision	JEN revised regulatory proposal
Inter DB Charges and Revenues	Not considered but in response to AER concerns over ability for JEN to recover under the Rules	Distribution services provided by other DNSPs An event where the DNSP incurs charges for distribution services provided by other DNSPs (net of distribution services provided to other DNSPs) where those charges are inputs to the provision of standard control services, and for which provision has not otherwise been made for the recovery of these charges from customers. For this event, the term "distribution services" is as defined in the Rules. *Materiality Threshold* No materiality threshold – however, to the extent the AER considers it has an ability to set a materiality threshold in a distribution determination (or otherwise), for this purpose, an event is considered to materially increase or decrease costs where JEN's administrative costs of applying for the pass through event are less than costs incurred.

16.5 Compliance with the Rules

The AER's determination as to whether additional pass through events should be allowed in a determination is governed by the NEO in section 7 of the Rules and the revenue and pricing principles in section 7A. However, the AER's draft decision clearly does not have regard to the either the objective or principles in the Rules. JEN submits that its proposed pass through events should be accepted by the AER on the basis that they are consistent with both the NEO and the revenue and pricing. In particular, JEN's proposed pass through events have regard to the principle in:

- section 7A(2), as the events provide network service providers with a reasonable opportunity to recover at least efficient costs incurred in providing direct control network services

- section 7A(3), as the events provide network service providers with effective incentives to promote economic efficiency with respect to direct control network services.

Moreover, the proposed pass through events achieve an outcome that is consistent with the long term interests of consumers of electricity and the NEO, which is to:

> promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –
>
> (a) price, quality, safety, reliability and security of supply of electricity and
>
> (b) the reliability, safety and security of the national electricity system.

17 Demand management incentive scheme

- JEN has incorporated the AER's draft decision without change.

17.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN accepted the AER's proposed demand management incentive scheme (**DMIS**) and dollars as set out in its F&A paper.

17.2 Summary of AER's draft determination and decision

In its draft decision, the AER has confirmed its proposed DMIS as set out in its F&A paper. The DMIS will comprise two parts:

- *Part A* – the DMIA component
- *Part B* – foregone revenue component.

Part A will be capped in the forthcoming regulatory control period at $200,000 ($1 million over the forthcoming regulatory control period) for JEN.

Part B will be uncapped but subject to the restrictions set out in the DMIS. Part B will be applied consistent with the methodology set out in the DMIS.

17.3 JEN's response to AER's draft determination and decision

JEN accepts the AER's DMIS and, where relevant, has incorporated its draft decision without change.

18 Building block revenue requirements

18.1 Summary of JEN original regulatory proposal

Table 18-1 shows JEN's total required revenues for each year of the next regulatory control period included in its original regulatory proposal.

Table 18-1: JEN revenue requirement in its original regulatory proposal

Building block	2011	2012	2013	2014	2015	Total
Return on capital	80.1	89.1	97.9	104.9	110.5	482.5
Return of capital	27.7	32.7	37.9	36.9	34.7	169.9
Operating expenditure	62.6	61.1	62.9	66.7	66.1	319.4
Taxation allowance	12.2	7.3	8.9	8.9	8.9	46.2
Carry-over mechanism	19.6	13.6	15.7	0.7	0	49.6
Adjustments	-0.9	-1.7	-1.2	-1.2	-3.2	-8.2
Building block revenue requirement	201.4	202.3	222.0	217.0	217.0	1,059.7

JEN specified price paths for its standard control services to smooth its required revenue for the standard control services and achieve price stability over the next regulatory control period. This smoothing gives rise to the price paths (P_0 and X factors) set out in section 13.1 of its original regulatory proposal.

18.2 Summary of AER's draft determination and decision

In its draft decision the AER considered that, in order to make the proposal acceptable to the AER, JEN would be required to amend the total revenue for each regulatory year of the regulatory control period in its regulatory proposal. The AER's replacement revenue requirement was provided in Table 18-2.

The main reasons for the difference in total revenue are:

- the AER not approving JEN's opening capital base and requiring amendments that would significantly reduce JEN's forecast capex
- the AER not approving JEN's opex

- the AER not approving JEN's WACC.

Table 18-2: AER draft decision for JEN's revenue requirement

Building block	2011	2012	2013	2014	2015
Return on capital	71.83	75.01	78.44	81.89	85.27
Return of capital	26.91	30.66	34.68	38.96	32.28
O&M	51.09	50.15	51.44	56.26	57.55
S factor true-up	-2.17	0.27	0.74	0.76	0.40
Carry-over amounts	18.75	15.55	19.49	3.60	0.45
Benchmark Tax liability	2.31	2.76	3.28	3.72	2.99
Revenue requirement	168.71	174.40	188.06	185.20	178.94

Price path for standard control distribution services

The AER rejected JEN's proposed Po and X factors in favour of a 1.46 (price decrease) Po and X factors of 0, 0, 3 per cent (price decrease) and 6 per cent (price decrease) respectively for years 2 to 5.

18.3 JEN's response to AER's draft determination and decision

As documented throughout this regulatory proposal, JEN has responded to specifically to each cost of service building block item. The culmination of these responses and JEN's updated capex, opex, demand and WACC forecasts is the revenue requirement set out in Table 18-3.

Table 18-3: JEN revenue requirement

Building block	2011	2012	2013	2014	2015
Return on capital	78.88	88.62	99.32	108.37	116.45
Return of capital	26.98	32.88	39.45	45.35	45.50
O&M	70.19	69.55	71.27	78.87	86.44
S factor true-up	-2.20	-0.88	-0.42	-0.42	-2.76
Carry-over amounts	15.00	11.40	14.22	-2.06	-3.14
Benchmark Tax liability	2.02	2.71	3.71	5.43	5.39
Revenue requirement	190.86	204.29	227.54	235.54	247.87

18.3.1 Price path for standard control distribution services

The AER's draft determination set a price path comprising a 1.46 (price decrease) in 2011 and X factors of 0, 0, 3 per cent (price decrease) and 6 per cent (price decrease) respectively for 2012 to 2015. The AER stated that it had set this price path in order to align the 2015 building block revenue requirement (BBRR) with JEN's forecast revenues in that year.

JEN notes that the AER's proposed price path does not achieve this intent because it significantly under recovers relative to the BBRR in the early years of the period and then over-recovers in 2015 by some 3 per cent.

JEN considers that other price path options exist which better align JEN's expected revenues and its BBRR over each year of the period. Table 18-4 sets out price path scenarios that achieve the final year BBRR alignment required by clause 6.5.9(b)(1) of the Rules while also providing JEN sufficient upfront cash flow to support its significant capex program for the forthcoming regulatory control period.

Table 18-4 sets out JEN's proposed price path and demonstrates how this complies with clauses 6.5.9(b)(2) and 6.5.9(1)(b)(3).

Table 18-4: JEN's revised price path

Building block	2011	2012	2013	2014	2015	NPV
Revenue requirement	190.86	204.29	227.54	235.54	247.87	821.58
Forecast revenue	199.09	210.13	219.86	230.27	243.00	821.58
Price path	-16.41%	-3.00%	-3.00%	-3.00%	-3.00%	n/a

18.4 JEN's revised regulatory proposal

JEN's revised revenue requirement and price path are set out respectively in Table 18-3 and Table 18-4.

19 Public Lighting

JEN has incorporated the AER's proposed public lighting inputs except for the following where JEN has:

- applied revised WACC, labour and material escalators and forecast CPI to the public lighting model
- changed the T5 light failure rate from 11.2 per cent to 19.6 per cent
- revised the forecast of the take up rate of retrofitting MV80 lights to T5 lights.

19.1 Summary of JEN's original regulatory proposal

JEN's proposed public lighting charges for the forthcoming regulatory control period were set out in Table 19-34 of its original regulatory proposal[483]. The proposed charges were based on the AER's draft public lighting model issued on 18 September 2009.

JEN filled in the AER's draft model without modification (Appendix 16, Part 3, Public lighting model) on the proviso that its use of the AER's draft model should not be seen as an endorsement of its model for the purposes of making a determination on JEN's public lighting costs or charges.

Subsequent to the lodgement of JEN's original regulatory proposal, JEN resubmitted on 24 February 2010 to the AER proposed public lighting charges. The charges were produced from the AER's final preferred public lighting model released on 10 November 2009.

19.2 Summary of AER's draft determination and decision

In the draft decision, the AER accepted JEN's classification of public lighting as an alternative control service. The AER decided that the public lighting charges will be subject to a price cap and JEN is required to demonstrate compliance with the price cap through annual pricing approval process and be consistent with the AER's final decision for the relevant regulatory period.

The AER rejected JEN's proposed public lighting charges on the basis that the opex and capex inputs do not reflect the efficient costs of providing public lighting services over the forthcoming regulatory control period. The AER's draft decision on public lighting charges for JEN is set out in Table 19.48 of its draft decision[484].

[483] JEN, *Regulatory Proposal 2011-15*, 30 November 2010, p. 247.

[484] Draft decision, p. 827.

19.3 JEN's response to AER's draft determination and decision

JEN notes that the AER has accepted a number of cost inputs proposed by JEN without change, but has rejected other inputs. JEN's areas of concern are:

- labour and material escalation
- failure rates of T5 lights between bulk changes
- weighted average cost of capital

JEN provides the following information for the AER's consideration before making a final decision on the public lighting charges for the forth coming regulatory period.

19.3.1 Labour and material escalation

The AER has incorporated JEN's proposed labour rates, which were the same as the AER's published labour rates in its 2009 final decision. JEN's proposed labour rates are:

- $71.41 per hour for normal hours
- $82.12 per hour after hours (night patrols).

However, the AER did not accept JEN's proposed real escalation rates for labour and poles and brackets. Instead, the AER applied the escalators that it considered to be fair and reasonable for standard control services in the draft decision. The AER also applied a 45 percent steel escalator to poles and brackets.

Table 19-1 shows the AER's draft decision on labour escalators including JEN's original and revised proposed labour escalators.

Table 19-1: AER's draft decision labour escalators including JEN's original and revised proposed labour escalators (per cent, per annum)

Item	2011	2012	2013	2014	2015
AER's draft decision labour escalators	0.87	1.48	1.89	1.87	0.69
JEN's original proposed labour escalators	2.43	2.63	2.73	2.63	2.43
JEN's revised proposed labour escalators	1.79	2.21	2.35	2.09	1.89

JEN has reviewed its labour and material escalators in light of the AER's draft decision. JEN has applied a 45 percent weighting to the steel escalator for poles and brackets. JEN arguments supporting the revised proposed labour and material escalators are set out in sections 8.11.3 and 8.12.4 respectively of JEN's revised regulatory proposal.

19.3.2 Failure rates of T5 lights between bulk changes

In section 19.8.2 of the draft decision, the AER notes:

> "Each Victorian DNSP, except for United Energy, proposed annual failure rates for MV80s which are unchanged from the proposed failure rates for 2010." [Emphasis added].

The above is incorrect to the extent that JEN also proposed annual failure rates for MV80 lights that were different to the currently applying for 2010. JEN proposed failure rate of 19.6 per cent over a 4-year period (i.e. between bulk changes), which the AER has accepted.

In the discussion on the failure rates of T5 lights, the AER concludes:

> "Further, the AER considers that the information provided to it by the Victorian DNSPs was insufficient for it to determine that failure rates for T5 lights should be higher than the rate of 11.2 per cent, as established in the AER's 2009 final decision.
>
> It is recognised that further information on the performance and failure rates of energy efficient luminaires and components may come to hand over time. However, in the absence of sufficient information, the AER will continue to adopt 11.2 per cent as the proportion of T5 lights that fail between bulk changes."

For this draft decision, the AER has largely relied on the AER's 2009 final decision[485] when making this draft decision on the failure rates of T5 lights between bulk changes. In the AER's 2009 final decision, the AER noted:

> "In reviewing the evidence on failure rates, the AER has adopted the VSPLAG technical report[486] finding for the failure of lamps, also used by SP AusNet, in setting the benchmark assumption of an 8.6 per cent lamp failure rate."

JEN contends that the failure rate adopted by the AER in the 2009 final decision is significantly below the predicted failure rate and maintenance factor noted in the VSPLAG report[487]. JEN reasons are set out below.

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485 AER, *Energy Efficient Public Lighting Charges – Victoria (Final)*, February 2009, p. 34.

486 Ibid., p. 7.

487 Victorian Sustainable Public Lighting Action Group (VSPLAG), *Evaluation of Low Energy Light for Minor Road Lighting, Twin 14 & 24W T5, 32 & 42W CF, 50W HPS*, 12 March 2008. pp. 8-9.

Firstly, the lamp failure is not the only type of component failure that occurs in a T5 light. A T5 light uses the same type of photoelectric cell that is used in the existing MV80 lights and these photoelectric cells are susceptible to failure.

Secondly, JEN is not aware of any evidence that suggests that the T5 lamp has a longer life than the MV80 lamp. Because there are two lamps in a T5 light, JEN considers there is a greater chance of a T5 light failure compared to a MV80 (which has only one lamp). By including the photoelectric cell failure rate with the T5 lamp failure rate, JEN believes that the T5 light failure rate will be the same, if not greater, than the MV80 lights.

This proposition is supported by the VSPLAG report[488] which concludes:

> T5, CF & 50W HPS low-energy lights have maintenance factors that exceed that of the 80W MV light.

It is important not to misinterpret the VSPLAG general findings[489] that states the T5 lights are:

> ...the T5 (twin 14W & twin 24W) & the compact fluorescent (CF) (32W & 42W) low-energy lights were comparable or better in performance than the current standard, the 80W MV.

The above is an overall evaluation. It is not simply based on failure rates alone but includes other assessment criteria such as energy efficiency, light output depreciation over time and colour rendition.

JEN requests the AER to reconsider the allowed failure rate for T5 lights. By changing the failure rate from 11.2 per cent to 19.6 per cent (which the AER has accepted for MV80 lights) the failure rates of T5 and MV80 lights will be aligned. If left unchanged, the minor road street lighting charges are skewed towards the uptake of T5 lights and are not cost reflective, given the VSPLAG assessment that T5 lights have maintenance factors that exceed that of the 80W MV light.

19.3.3 Weighted average cost of capital

JEN response to the AER's draft decision on the weighted average cost of capital is set out in chapter 11. JEN has applied its revised WACC in the JEN public lighting model in Appendix 19.1.

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488 Ibid., pp. 6-7.

489 Ibid., p. 3.

19.3.4 *Forecast of MV80 light retrofit to T5 light*

In the original regulatory proposal, JEN proposed the take up rate of retrofitting MV80 lights including new T5 installation in subdivisions as shown in Table 19-2 below. The forecast was based on the interest shown by municipal councils in JEN's distribution area. Councils sought prices for retrofitting the existing MV80 to T5 lights to prepare their business cases. Following a tender process, JEN communicated that the price would be $291.70 per retrofit in 2009.

In 2010, JEN undertook a similar process and the resulting price to retrofit one MV80 light to T5 was approximately {c-i-c}

. Note the final price has not been released to the municipal councils at the time of writing this submission. The increase is mainly due to the supplier's price increase for T5 lights. Refer to Appendix 19.3 for suppliers (Pierlite) advice on price increase. JEN expects the take up rate of retrofitting MV80 lights with T5 lights will be 25 per cent lower than the previous forecast due to the increase in the cost of retrofitting the lights.

Currently as at July 2010 no council in JEN's distribution area has made requests or commitments to retrofit MV80's with the new T5 installation in the current year. It was JEN's expectation when forecasting November 2009 that matters between councils and JEN would have been more advanced in terms of the T5 take up than they currently are. As a result of the slower take up in February 2010, JEN adjusted the forecast for 2010 to zero and forecast the the commencement of the roll out of T5 lights to begin in 2011. JEN's forecast in its revised public lighting model is consistent with the 2011 commencement.

The revised forecast of the take up of T5 lights is show in Table 19-2.

Table 19-2: Cumulative forecast of the take up rate of retrofitting MV80 lights with T5 lights and new installations

Forecast number of energy efficient lights	2011	2012	2013	2014	2015
JEN's original proposed forecast of T5 2X14W	3,943	7,544	11,663	15,854	19,798
JEN's revised proposed forecast of T5 2X14W	3,154	6,035	9,330	12,683	15,838

19.3.5 *Traffic Management costs*

In the draft decision[490], the AER considers the Victorian DNSP's' forecast costs for traffic management have not been adequately explained. Notwithstanding this

490 Ibid., p. 805.

assessment, the AER has accepted JEN's proposed costs as appropriate in its draft decision. For completeness, JEN has provided the explanation for its proposed traffic management costs.

The Road Management Act 2004 imposes onerous conditions on utilities when they conduct works on road reserves. The Act requires distribution companies to apply to the Coordination Road Authority (in some cases there are more than one road authority) for consent before it undertakes works that are expected to cause significant delay to traffic. For those works requiring consent, VicRoads and or municipal councils (the Coordination Authorities) can impose conditions on how the works can be conducted, including restrictions on the times during which the works can be conducted.

This requirement imposes administrative burden and costs on JEN. Moreover, consent is generally given with onerous traffic management requirements and if the works are undertaken during weekends, there are additional costs due to labour penalty rates.

With traffic demand continuing to grow in urban areas, there is increasing pressure to minimise traffic disruption from events, incidents and planned works. In 2008, the definition of 'traffic impact works' were expanded to include works that cause significant delays to trams and buses.

To cover the additional costs on public lighting operations, JEN proposed $90,000 per annum for additional traffic management costs. These costs arise directly from meeting the obligations the Road Management Act 2004 and the expected increase with increases in road traffic.

19.3.6 2009 actual number of lights

In the February 2010, JEN used an estimate for the 2009 number of lights. The actuals for 2009 have now been finalised and as a result JEN has updated the public lighting model to include the finalised number of lights. With the exception of the T5 and MV80 lights, for the reasons outlined above, the change from year to year in the forecast volumes is identical to the forecast supplied in February.

19.4 JEN's revised regulatory proposal

JEN's revised proposed public lighting charges is shown in Table 19-1. The charges were produced by amending the AER's Draft Public Lighting Model that was issued with the draft decision. JEN has made the following changes to the public lighting model:

- updated the forecast CPI, to be consistent with the revised regulatory proposal – ("D36" General)

- updated the real pre tax WACC to be consistent with the WACC in the revised regulatory proposal – ("C28" General)

- applied the revised external labour rate escalators that is consistent with the revised regulatory proposal – ("D12:H13" O&M)

- applied the revised 45 percent steel escalator to poles and brackets consistent with AER draft decision and revised regulatory proposal – ("D72:H72, D74:H74" Capex)

- revised the forecast of the take up rate of retrofitting MV80 lights with T5 lights – ("F80:L80" General)

- linked traffic control cost split for MV80 and T5 lights to the take up forecast of T5 lights. JEN did not make any change to the traffic control costs allowed in the draft decision – ("D44:H44", "D159:H159" O&M)

- changed T5 light failure rate (between bulk lamp change) to 19.6 per cent – ("D142:H142" O&M)

- updated number of lights for 2009 to reflect actual volumes ("F53:F74").

Table 19-3: Tariff Outputs of AER Draft Public Lighting Model

Light Type	Charge $ per year				
	2011	2012	2013	2014	2015
Existing Lights					
Mercury Vapour 80 watt	37.34	40.55	42.58	44.77	47.38
Sodium High Pressure 150 watt	72.57	77.39	80.94	84.66	88.87
Sodium High Pressure 250 watt	74.39	79.39	83.05	86.89	91.25
55W Ind	46.67	50.68	53.23	55.97	59.23
Fluorescent 20 watt	46.67	50.68	53.23	55.97	59.23
Fluorescent 40 watt	46.67	50.68	53.23	55.97	59.23
Fluorescent 80 watt	46.67	50.68	53.23	55.97	59.23
Mercury Vapour 50 watt	46.67	50.68	53.23	55.97	59.23

Light Type	Charge $ per year				
	2011	2012	2013	2014	2015
Mercury Vapour 125 watt	54.89	59.61	62.60	65.82	69.66
Mercury Vapour 250 watt	71.42	76.22	79.73	83.41	87.60
Mercury Vapour 400 watt	80.34	85.75	89.69	93.84	98.55
Sodium High Pressure 50 watt	90.71	96.74	101.17	105.82	111.09
Sodium Low Pressure 90 watt	76.93	82.04	85.79	89.74	94.21
Sodium High Pressure 100 watt	99.42	106.03	110.88	115.98	121.76
Sodium High Pressure 400 watt	98.94	105.59	110.45	115.56	121.36
Metal Halide 70 watt	95.96	104.21	109.44	115.06	121.78
Metal Halide 150 watt	161.11	171.81	179.68	187.94	197.30
Metal Halide 250 watt	159.94	170.70	178.56	186.81	196.18
Incandescent 100 watt	58.25	63.25	66.43	69.84	73.92
Incandescent 150 watt	72.81	79.07	83.04	87.31	92.40
Sodium High Pressure 250 watt (24 hrs)	116.05	123.86	129.56	135.55	142.34
Metal Halide 100 watt	161.11	171.81	179.68	187.94	197.30
Energy Efficient Lights					
T5 2X14W (retrofitted from 80W MV)	26.80	28.04	29.17	30.37	31.67

20 Other alternative control services

- JEN has done its best to incorporate the intent of the AER's draft decision, with some necessary amendments, including:
  - correcting what JEN perceives to be AER errors in interpreting the times put forward in JEN's original proposal
  - using JEN's revised proposed labour and material escalators
  - updating the indirect cost allocation to reflect actual 2009 costs
  - updating the Formway contract price for meter tests
  - providing additional information, where explicitly requested by the AER in its draft decision and updating the relevant charges accordingly
  - revising the naming of some of the services to be consistent with the terms used in the AER's draft decision.
- JEN's incorporation of the draft decision should not be taken as JEN's agreement to or endorsement of the AER's or Impaq's conclusions on the underlying or efficient costs of providing alternative control services
- JEN's systems are not currently able to record the true cost of providing individual alternative control services and these costs can only be estimated
- JEN is currently putting in place business processes to collect better and more detailed information on the costs of individual services in the forthcoming regulatory control period
- JEN has also presented additional information that JEN believes the AER should consider before making a final decision on charges for alternative control services.

20.1 Summary of JEN's original regulatory proposal

In its original regulatory proposal, JEN undertook a comprehensive bottom-up costing exercise to determine the costs of providing ACS, except for metering data provider services for unmetered supplies with type 7 metering installations and supply enhancement at customer request-reserve feeder, which are based on a top-down approach. JEN completed further work in response to AER questions on its cost estimates.

The charges JEN developed reflected its best estimate of the actual direct costs JEN incurs in providing the service to the customer on the basis of the information available to JEN. No profit margin or indirect costs recovery for JEN was included in its proposed charges.

JEN took the opportunity to simplify and rationalise the legacy structure of the charges. JEN also introduced new services that will become available in the upcoming regulatory period due to the roll out of Advanced Interval Meters.

20.2 Summary of AER's draft determination and decision

In chapter 20 of the draft decision[491] the AER has set out its consideration on alternative control services proposed by the DNSPs.

The AER stated that the Victorian DNSPs will be able to levy charges for alternative control services (fee based and quoted) over the forthcoming regulatory control period on the basis of the AER's final determination on pricing and control mechanisms for these services. For fee based services the AER will determine a fixed fee, whereas for quoted services the AER will determine the hourly labour rate and basis for materials charges which can then be applied to the particular work which needs to be performed.

The AER did not set prices for the Victorian DNSPs' remote metering services, which are facilitated by the rollout of advanced metering infrastructure (AMI) in Victoria. This is because the regulatory arrangements relating to the AMI rollout, and associated remote metering services charges, are set out in a legislative instrument (Order in Council made by the Victorian Governor in Council) which is separate to the Rules. Accordingly, the AER will regulate the new services that are facilitated by AMI under the Victorian DNSPs' distribution licences and Guideline 14.

The AER rejected JEN's proposed classification of routine new connection services to be classified as standard control services. The AER has made a draft decision to classify all routine connection services as alternative control services with the following distinction[492] being made as follows:

- treatment as fee based services for customer connections below 100 amps
- treatment as quoted services for customer connections above 100 amps.

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[491] Draft decision, p. 849.

[492] Ibid, p. 24.

Moreover, the AER has also requested that JEN submit proposed prices for new connections services where JEN is not the responsible person for metering, for application in 2014 and 2015.

The AER noted in its draft decision that it had used the Impaq Consulting's (Impaq) advice on the electricity industry labour rates and times taken to perform alternative control services to inform its review of all fee based and quoted service prices.

Having reviewed JEN's proposed prices and charges, the AER has rejected JEN's proposed prices for fee based alternative control service and the charge out labour rates for quoted services for the forthcoming 2011–15 regulatory control period.

The AER's approved prices for fee based and charge out rates for quoted alternative control service – with the exception of a number of services for which the AER has requested further information – are set out in appendices[493] O.2 and O.3 respectively.

20.3 JEN's response to AER's draft determination and decision on fee based services

In this revised proposal, JEN has:

- sought to implement the AER's stated intent of accepting the proposed times to complete services where the proposed times were within the reasonable range determined by Impaq, and to otherwise apply the high point of Impaq's range
- in addressing the bullet above, corrected what JEN perceives to be AER errors in interpreting the times put forward in JEN's original proposal (refer to Appendix 20.2). This may have been caused by the complexity of the original models submitted by JEN. JEN has simplified the model that has been re-submitted with this revised proposal (refer Appendix 20.3)
- used JEN's revised proposed labour and material escalators (rather than the escalators used by the AER in the draft decision) to move costs between years and to calculate X-factors
- updated the indirect cost allocation to reflect the actual 2009 costs as per JEN's 2009 Regulatory Accounts, resulting in the allocator being reduced to 6 per cent from 7 per cent
- updated the Formway contract price to {c-i-c} for meter tests (reduction from {c-i-c} being $2009). This is now consistent with JEN's cost build

493 Draft decision, Appendices, pp. 314-325.

up for all fee based alternative control services, which were based on costs valid for 2008

- provided additional information, where explicitly requested by the AER in its draft decision and updated the relevant charges accordingly

- revised the naming of some of the services to be consistent with the terms used in the AER's draft decision.

As a result of the above issues, even though JEN has sought to implement the AER's draft decision, the prices for alternative control services in this revised proposal are different to those shown in AER's Appendix O2.

The incorporation of various elements of the AER's draft decision with respect to alternative control services should not be taken as JEN necessarily agreeing with or otherwise endorsing the AER's or Impaq's conclusions on the underlying or efficient costs of providing alternative control services. JEN's systems over the 2006 – 2010 regulatory period were not configured in a manner that permitted the recording of the actual quantum of costs associated with providing individual alternative control services. Therefore, on the basis of the information that is available to JEN, the relevant costs have been estimated by JEN on what JEN considers to be a reasonable basis. JEN is currently putting in place business processes to collect better and more detailed information on the costs of individual services in the forthcoming regulatory control period.

While JEN has, in this revised proposal, incorporated the intent of the AER's draft decision in the following subsections, JEN has also presented additional information that JEN believes the AER should consider before making a final decision on charges for alternative control services. In JEN's view the information presented is relevant to the AER's further consideration of the adjustments the AER made to JEN's original proposed prices for fee based services and those subsequently resubmitted, including routine connection services for 2011. The adjustments made by the AER are:

- taking the highest point of Impaq's recommended range of labour rates for each of the services and reducing it by 5 per cent to account for AER's assessment that DNSPs should be only be allowed to earn a 3 per cent profit margin

- for JEN's scheduling team rates, applying the midpoint between Impaq's recommended back office rate and line worker rate where appropriate

- including the scheduling team times in the back office times for new connection services including temporary supply

- where the proposed times were found to be above the reasonable range determined by Impaq, applying the highest point in the range of the time taken to perform alternative control services
- in equating the approved prices to 2011 dollars (from 2008 dollars as submitted by JEN), applying the same labour and materials escalators the AER applied to standard control services in this draft decision, as set out in Appendix K.

The AER rejected[494] JEN's proposed prices for meter equipment tests and has requested further information from JEN on the costs of providing meter equipment test services, specifically a transparent breakdown of the Formway charge, or a new cost build up for these services.

The AER has also requested JEN submit proposed prices for new connections services where JEN is not the responsible person for metering, for application in 2014 and 2015.

Below, JEN provides additional information that is relevant to the adjustments summarised above, as well as other additional information. Having considered the additional information provided by JEN (or any other relevant information), the AER may in its final decision set different charges for alternative control services compared to those put forward in this revised regulatory proposal. In that instance, JEN requests that the AER provides JEN with the opportunity to make consequential changes to JEN's forecast data model, which calculates the inputs into the PTRM. The consequential changes need to be made to avoid double recovery (or under-recovery) of base year operating costs.

20.3.1 Line worker and back office hourly charge out rates during business hours

Impaq Consulting recommended[495] a range of labour charge out rates for fixed fee and quoted services based on its analysis of services provided by other DNSPs. The AER considered Impaq's recommendations and specifically agreed with Impaq's discussion on profit for alternative control services, that is:

> Alternative Control Services are not capital intensive and hence the application of the standard building blocks of Return of Capital and Return on Capital do not yield meaningful profit margins. However in similar service industries profit margins of from 3% to 8% are common. Given the low risk nature of the revenue earned by the

[494] Draft decision, p. 871.

[495] Impaq Consulting, *Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, including final Impag report – Jemena confidential version, pp. 48-49.

> DNSPs for ACS services it is arguable that margins should be at the lower end of the range.[496]

Consequently, the AER amended Impaq's high case labour charge out rates by removing 5 per cent, to account for the AER's view that the maximum allowable profit margin of 3 per cent.

JEN notes the consultant's view that the revenue earned by DNSPs for alternative control services are of low risk. JEN notes it is just as exposed to the vagaries of the market conditions as the other businesses in similar industries. For example many alternative control services are affected by economic conditions, including: requests for services such as routine connections including temporary supply, covering of low voltage mains, supply enhancement, elective underground and service vehicle visits. Consequently the revenues of the DNSPs appear to be just as impacted.

JEN has reviewed Impaq's analysis of charge out rates. Specifically JEN refers to Impaq's calculation of available hours[497] used to generate their business hours and after hours charge out rates. When calculating the available hours, Impaq appears not to have taken into consideration the impact of non-productive activities such as:

- administrative time for such matters as completing timesheets, attending working group meetings and briefings
- staff training
- stand-down time required under awards for safety reasons between shifts
- major emergency work requiring staff to be reassigned to other work
- impact of inclement weather on the productivity of field staff.

It would appear that Impaq have omitted the important step of converting available hours into chargeable hours, and have only used available hours. JEN estimates the chargeable hours to be about 10 per cent lower than the available hours recommended by Impaq.

20.3.2 Line worker hourly charge out rates during after hours

The draft decision reflects confusion about JEN's proposed after hours charge out rate for a line worker in the cost build up model for the fee based alternative control services including the new and temporary connection services. In the original

496 Draft decision, p. 852.

497 Impaq Consulting, *Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, including final Impag report – Jemena confidential version, Table 10, p. 36.

regulatory proposal JEN had used the business hours charge out rate and applied an adjustment factor in the cost model with a footnote stating: "the linesmen rate for after hours work reflects the additional costs associated with after hours work including average call out times". In hindsight, this did not adequately explain the reasons for the high labour cost for after hours work. This may be why Impaq erroneously concluded that:

> "There is a premium built into the rates for out of hours service that is not justified based on costs, rather it appears to have been introduced as a discouragement for customers to use services out of hours."[498]

No such premium was built into JEN's proposed prices. Impaq does not give a basis for the above conclusion.

JEN is required to pay its line workers for a minimum of four hours when called out to perform a job after hours regardless of the time taken to perform the job. The Enterprise Bargaining Agreement (EBA) stipulates such a payment for after hours work concerning line works who are members of the Electrical Trades Union (ETU). JEN understands that this requirement to pay four hours minimum time is common in the industry. The relevant sections of the EBA are included in Appendix 20.4.

JEN's cost of undertaking after hours work varies depending on the number of customer requests for after hours services received in a given day. JEN's records indicate customers seldom request after hours services. After hours service requests are generally from business customers or building developers who request a service crew to undertake the work at a precise time and day so that the work can be coordinated with other work on site.

20.3.3 Scheduling team hourly rate

The AER's draft decision[499] states:

> "In addition to back office worker time, some of Jemena's proposed alternative control services prices incorporate work by a job scheduling team. Impaq did not provide advice on a reasonable charge out rate for a scheduling team worker, however noted that the work is highly similar to that performed by a back office worker. While the other Victorian DNSPs do not specifically incorporate work by a scheduling team, their alternative control service scheduling time is performed either by a back office or line worker. Jemena's proposed rate for the scheduling team falls between its proposed rates for back office and line workers."

[498] Impaq Consulting, *Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, including final Impag report – Jemena confidential version, p. 4, as also noted by the AER on p. 867 of the draft decision.

[499] Ibid., p. 867.

Consequently, the AER concluded[500]:

> “For Jemena's scheduling team labour, the AER considers that a rate at the midpoint between the adjusted Impaq recommended back office rate and line worker rate would reflect a reasonable rate due to the nature of the work carried out by the scheduling team being tasks including those of a back office worker and a line worker”.

JEN notes that the work of a scheduler is not highly similar to that performed by a back office worker. The skill set of a scheduler, who is involved in relation to a connection service, is very different to that of a back office staff member. A scheduler is generally a former line worker. An important prerequisite for a scheduler is a thorough understanding of the field work to be undertaken by a line worker. A scheduler is required to know the typical time taken to do the various field tasks, the material required for each of the tasks, likely problems that can occur when completing the tasks and the hazards associated with each of the jobs. These attributes are necessary to efficiently schedule the service orders each day and assign the jobs to the appropriately skilled service crews and ensure availability of required materials.

20.3.4 Time taken to perform fee based alternative control services

To enable the AER to further consider the appropriate time taken to perform the various tasks, JEN provides a detailed description of the end to end process involved in each of the tasks below.

20.3.5 Back office function

The back office functions are very similar for:

- Routine connections (customers below 100 amps)
- Temporary supply services
- Service vehicle visits.

The end to end process of the back office staff is described in detail in Appendix 20.5.

Not all connection service orders are completed without complications or additional issues arising. On average, each new connection staff member takes 12 to 15 calls daily. The time spent on each call can vary between 1 to 20 minutes and in some cases much longer depending on the type of inquiry and the amount of investigation time a call may require.

500 Draft decision, p. 868.

The type of inquiry can range from customers seeking information on new connections, rescheduling of connections already processed, and amendments to connection requests. For example, a three phase business connection may not proceed because there is insufficient supply capacity in the network adjacent to the connection address.

Service vehicle visits (generally arranged via appointments) are generally used for additions and alterations to existing premises. The back office functions for these services are similar. For completeness, JEN has described the process in Appendix 20.5.

20.3.6 Scheduling function

The scheduler's functions are very similar for:

- Routine connections (customers below 100 amps)
- Temporary supply services
- Service vehicle visits
- Wasted service vehicle visits.

The end to end process of the scheduling team is described in detail in Appendix 20.5.

20.3.7 Back office function in relation to manual re-energisation and de-energisation services

In Table 21 of Impaq's report[501], Impaq notes there will be a need for some manual intervention (unlike for a re-energisation) to ensure life support customers are not disconnected, but Impaq do not appear to reflect the expected difference in their recommended time estimate for de-energisation (compared to re-energisation).

This table is reproduced below in Table 20-1.

[501] Impaq Consulting, *Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, including final Impag report – Jemena confidential version, p. 50.

{c-i-c}

The back office functions in relation to re-energisation and de-energisation are performed by the same back office staff. It is noteworthy, that JEN has distinguished the back office time taken to re-energise compared to de-energise, given that there is a need for manual intervention to ensure life support customers are not disconnected. The activity volume of re-energisation and de-energisation are generally the same, given that re-energisation generally follows de-energisation for a move in/move out.

The other two DNSPs have averaged the time across both functions, but JEN has chosen to reflect the extra effort that goes into the de-energisation process by apportioning a greater portion of the back office time to de-energisation. When the times proposed in the original regulatory proposal for both the JEN functions are averaged, the result is 0.116 hours – close to the Impaq's recommended upper range of 0.11 hours.

20.3.8 Field line worker time in relation to wasted service vehicle visit

In Table 21 of Impaq's report[502], Impaq notes:

> "It would be expected that the field staff time would be less for a wasted service vehicle visit than for a service vehicle visit. It would be expected that an allowance of about 10 min on site plus 20 min travelling time would be appropriate– total time of 1 hour (30 min times crew of 2)"

Service vehicle visits are arranged by appointments by the back office staff with the registered electrical contractor (REC) undertaking additions or alterations to existing supply connections. These works are booked in one-hour blocks per service vehicle appointment. When on arrival of the service crew (two line workers in a crew), it is found that the customer or REC is not ready for the scheduled work, then the service crew cannot be productively employed elsewhere. The crew would have already spent some time travelling to the work site and the remaining time would be about 30 minutes. The crew is expected to attend to the next scheduled appointment. Appointments are generally booked back to back. Given the short duration of each service vehicle visit, there is insufficient time on that day to schedule further jobs. JEN has no choice but to recover the costs from the person who has requested the service vehicle visit.

20.3.9 Proposed prices for meter equipment tests

The AER has rejected JEN's proposed prices for meter equipment tests on the basis that the Formway contract rate included within the build up of the proposed prices has not been appropriately justified. The AER considers the Formway rate proposed by JEN is substantially higher than rates for similar services carried out

502 Ibid., p. 51.

by other Victorian DNSPs. The AER has requested a transparent breakdown of Formway charge, or a new cost build up for these services.

The metering services with Formway were established with effect from 1 January 2005 following a closed tendering process. The original contract has since been revised. The tender process, related tender documents and the relevant sections of the Formway contract (Contract No. 4600001073) are contained in Appendix 20.6.

JEN's cost build up for all fee based alternative control services were based on costs valid for 2008. JEN had inadvertently used the Formway contract price of {c-i-c} for meter test in the cost build up model, which was the revised price for year 2009. Consequently, JEN has adopted the Formway contract price of {c-i-c} for a meter test in its revised regulatory proposal. This price for a meter test (referred to as 'Customer Paid Test') was established in 2008 and is shown on page 71 of Contract No. 4600001073, dated 18 May 2008. The relevant sections of the contract showing are in Appendix 20.6.

It was not possible to obtain a written breakdown from Formway of the contract price of {c-i-c} for a meter test. However, the assessment of the contract price by JEN's metering staff, who manage the contract with Formway, is as follows:

- Travel time – {c-i-c}
- Test time – {c-i-c}
- Labour charge out rate of a specialist meter tester – {c-i-c}
- Light vehicle cost – {c-i-c}
- Provision of test equipment – {c-i-c}

JEN considers the above represents a reasonable breakdown of Formway's contract price of {c-i-c} per meter test.

This meter test service offer is intended for a customer or a retailer on behalf of the customer who requests a meter test to verify the meter is accurately measuring the energy consumption. This generally occurs after a high electricity bill complaint by a customer.

Requests for these services are in the order of 169 in 2008 and 186 for 2009. Consequently, the travel time associated with each meter test service is comparatively higher than a sample test of single and poly phase meters. These meter test jobs have to be scheduled such that the customer is given the opportunity[503] to witness the test.

Unlike sample meter tests, which are done relatively quickly due to the repetitive nature of the tests, individual meter tests initiated by a customer take considerably longer to undertake due to the interaction of the meter tester and the customer. If the meter is within the accuracy limits, the tester is often caught up in explaining the possible causes for the high energy consumption. Unlike sample meter tests of multiple meters, where a single report would suffice, Formway is required to produce a separate report for each customer initiated meter test and often additional time is spent liaising with JEN's Stakeholder Relations team in responding to the ombudsman's enquires in relation to the customer's high electricity bill.

JEN contends that Formway's contract price of {c-i-c} per meter test has been properly established by a tender process. The price is an average cost of undertaking a customer initiated meter test for a range of single and poly phase Type 5 & 6 meters.

JEN in its original regulatory proposal submitted prices for:

- Meter Test - test single and multiple phase installation with annual consumption of < 160 MWh
- Meter Test – Type 5 & 6 meter installation for first tier customers with annual consumption > 160 MWh.

JEN proposed a single price for both the meter test categories, as the current underlying costs of testing various meters are similar. The energy consumption threshold of 160 MWh has no bearing on the cost of meter tests.

To be consistent with the AER's terminology in the draft decision, JEN has revised the names of the meter test services to:

- Re-test types 5 and 6 metering installations for first tier customers with annual consumption less than 160 MWh
- Re-test types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh.

[503] Clause 5.4 (b) of the Electricity Customer Metering Code – 'a customer is entitled to be present when a test of metering equipment is carried out under clause 5.1'.

20.3.10 New connections services where JEN is not the responsible person for metering

The AER requested JEN submit proposed prices for new connections services where JEN is not the responsible person for metering, for application in 2014 and 2015.

JEN's proposed prices for routine new connection services in the original regulatory proposal are exclusive of the meter costs associated with a new supply connection. This is because JEN proposes to recover all the costs associated with the provision of a meter in accordance with the AMI Cost Recovery Order in Council.

In response to the AER's request, JEN has included proposed prices for new connections services where JEN is not the responsible person for metering for application in 2014 and 2015. For the reason given above, the proposed prices are identical to the prices for new connections services where JEN is the responsible person. The prices are shown in Table 20-2.

20.3.11 X factors to apply to fee based alternative control service prices

JEN proposed a price path where each year the charges are adjusted by (1+CPI)(1–X), where X reflects the escalation of cost inputs to the service in real terms. JEN calculated different X factors for each year of the forthcoming regulatory control period by breaking down the costs of the services into individual labour and material components and applying labour and materials escalators, forecast by BIS Shrapnel and SKM respectively.

The AER has requested JEN to revise the proposed X factors by applying the labour and materials escalators the AER has approved for standard control services (set out in Appendix K). JEN has revised the X-factors and they are based on JEN's revised labour and materials escalators for standard and alternative control services. Discussions supporting JEN's revised labour and materials escalators are in sections 8.11 and 8.12. JEN's has revised X-factors for each of the fee based services in accordance with its revised labour and materials escalators and they are shown in section 20.6.3 below.

20.3.12 Routine connections (customers above 100 amps)

In the AER's distribution determination[504] and draft decision[505], the AER classified routine connection (more than 100 amps) as quoted alternative control services. Based on the AER's decision, JEN has not proposed any fee based services for routine connection to customers requiring above 100 amps. JEN notes that

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[504] Draft determination, p. 8.

[505] Draft decision, p. 890.

connections above 100 amps require current transformers for metering and connections equal to or below 100 amps do not require current transformers.

JEN notes that the AER has incorrectly included four fee based services in Table[506] O.9 that are now classified as quoted services. They are:

- *routine connection*—three phase CT connected metering installation including energisation—BH
- *routine connection*—Three phase CT connected metering installation including energisation—AH
- *provision and connection of current transformers for new premises*—before hours
- *provision and connection of current transformers for new premises*—after hours.

20.3.13 Tax liability recover for routine connections

JEN notes that, under the AER's approach to routine connections, unlike the current ESCV approach, there will be no regulatory asset base to which the assets created by a routine connection (**routine connection assets**) can be added.

Given the nature of routine connection assets, JEN has no choice but to capitalise the costs of creating these assets for tax purposes, thereby incurring a tax liability. JEN notes that neither JEN's original proposed charges for routine services, nor the charges put forward in the AER's draft decision provided for the recovery of the tax liability associated with routine connection assets.

Clause 7A(2)(a) of the NEL requires that a regulated DNSP should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services, be they ACS or SCS.

As JEN has no choice but to incur the tax liability, JEN believes the liability to be an efficient cost and, therefore, considers that the AER must provide a markup on the bottom-up physical routine connection costs to allow for the recovery of the associated tax liability. JEN's ACS pricing models submitted with the revised regulatory proposal include a placeholder for such a mark up.

20.3.14 Reserve feeder

In an email to JEN on 7 July 2010, the AER requested that in its revised proposal JEN should provide information on the underlying cost to it of providing the reserve feeder service. This information is provided in Appendix 20.7.

[506] Draft decision, *Appendices*, p. 314-316.

20.4 JEN's response on distinction between quoted and fee based alternative control services

In the AER conclusion on service classifications of fee based alternative control services for 2011 – 2015 regulatory period, the AER has included 'supply abolishment' as a fee based service. JEN has an issue with this proposed treatment because of the huge variability of costs. In JEN's original regulatory proposal[507], JEN included 'supply abolishment' as a quoted alternative control service for the forthcoming regulatory period. The AER in its draft decision has not made any comment on JEN's proposal to treat the service as a quoted service.

Subsequent to the release of the draft decision and in response to JEN's request for further information and clarification, in an e-mail[508] the AER stated:

> The AER's draft decision is that 'supply abolishment' be classified as a fee based service. The F&A classified 'supply abolishment' as a fee based service and the draft decision did not depart from that classification. It is noted that Jemena's regulatory proposal did not provide reasons for changing the classification.

JEN notes that 'fee based' and 'quoted' are not valid service classifications available to the AER under Part B of the Rules, which deals with service classification. Clause 6.2.1(a) of the Rule provides for the AER to classify distribution services as either direct control services or negotiated distribution services. Clause 6.2.2(a) provides that direct control services are to be further divided into two subclasses: standard control services and alternative control services. The Rules do not provide for any other classifications.

For clarity, JEN reiterates that its proposal had been and continues to be for supply abolishment to be classified as a direct control service and further classified as an alternative control service. This proposed classification was clearly stated on pages 214, 221 and 241-242 of JEN's original regulatory proposal. This classification is also consistent with the classification proposed for supply abolishment by the AER in its Framework and Approach Paper[509] and draft decision (where the AER considers this service to be an alternative control service).

JEN's rationale for proposing supply abolishment to be priced as a quoted, rather than a fee-based service is provided below.

Supply abolishment can range from simple removal of an overhead service cable to the removal of an underground cable from a substation, which may include the removal of the substation if the site is to be redeveloped. It is noteworthy that there is a well-established industry procedure for the abolishment of electricity supply

[507] JEN, *Regulatory Proposal*, 30 November 2010, p. 242.

[508] AER, *Email – From Darren Kearney to Anton Murashev*, 7 July 2010.

[509] AER, F&A, p. 133.

assets. Supply abolishment's can be initiated by the service applicants by first completing the Victorian Electricity Supply Industry form for supply abolishment (refer to Appendix 20.8). This form can be found on the websites of JEN and other DNSPs. The application form contemplates a variety of supply asset abolishment.

It is worth noting that removal of a builder's temporary supply is inclusive of the fee based 'temporary supply with co-incident abolishment' offered by JEN. Simple supply abolishment, consisting of removal of overhead service cables can be offered under the fee based 'service vehicle visit' service, which is commonly used for alterations and additions to an existing supply. Consistent with its current practice, JEN proposes to offer supply simple abolishment of overhead service cables as a fee based 'service vehicle visit' service. JEN considers that complex supply abolishment of large supplies (underground and overhead), including substation abolishment, are best offered as a quoted service, because the scope of works and costs can vary significantly from one job to another. JEN submits that its proposal to include underground supply and substation abolishment as a quoted service is consistent with long-standing industry practice in Victoria. JEN believes the AER should consider this additional information before making a final decision on the appropriate treatment for supply abolishment services.

20.5 JEN's response to AER draft determination on charges for quoted services

JEN has done its best to incorporate the AER's draft decision on the charges for quoted services.

The AER noted[510] that for a number of quoted services, the Victorian DNSPs have not provided information to the AER on the labour rates and terms of supply applicable to a number of these services, and in a form that would enable the AER to appropriately assess and compare rates and terms of supply across the range of services and DNSPs. Accordingly, the AER has not approved labour rates and terms of supply for all quoted services in this draft decision, and the DNSPs will be required to submit labour rates and terms of supply for those quoted services in their revised proposals, for consideration in the AER's final decision.

JEN has revised its quoted services (referred to as 'recoverable works' in its original regulatory proposal) in accordance with the AER's draft decision [511] to include:

- temporary covering of low voltage mains and service lines in accordance with the AER's decision to classify coverage of low voltage mains as quoted services for the 2011–15 regulatory control period

[510] Draft decision, p. 833.

[511] AER, op.cit., p. 890.

- routine connections (customers above 100 amps).

In its original regulatory proposal[512], JEN included 'elective underground service where an existing overhead service exists' and 'reserve feeder' as part of 'supply enhancement at customer request'. JEN considered elective underground service as a form of supply enhancement service requested by a customer. For consistency with the AER's decision, JEN has listed the elective underground service as a separate quoted service offering in its revised regulatory proposal.

JEN's revised regulatory proposal consists of the following quoted services:

- routine connections (customers above 100 amps)
- damage to overhead service cables caused by high loads—restoration of overhead service cables pulled down by transport vehicles transporting high loads
- high load escorts—lifting of overhead lines
- covering of low voltage mains and services
- rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting services
- supply enhancement at customer request – reserve feeder
- elective underground service where an existing overhead service exists
- complex supply abolishment.

JEN proposes to determine the charge for covering of low voltage mains by applying the labour charge out rates for quoted services plus $5 per tiger tail per use. JEN has adopted the cost of tiger tail on the basis of Impaq's validation of costs[513]. Tiger tails is a product name of standard covers for low voltage electrical mains.

Routine connections (customers above 100 amps) are connections that require current transformers (CTs). Consistent with its original regulatory submission, JEN will determine the charge for this service by applying the proposed labour unit rate per hour, with material and plant costs being passed onto customers at cost JEN incurs.

512 JEN, *Regualtory Proposal*, 30 November 2010, pp. 215 & 242.

513 Impaq Consulting, *Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, including final Impag report – Jemena confidential version, p. 54.

20.6 JEN's revised regulatory proposal

20.6.1 Revised proposed charges for fee based alternative control services

A prices comparison for fee based alternative control services is contained in Appendix 20.9, showing current price, original proposed prices ($2008), revised price ($2008), the AER's draft decision price and the revised price escalated to $2010.

JEN's revised proposed charges for fee based alternative control services in 2011 are set out in Table 20-2 and Table 20-3.

Table 20-2: – Routine connection services ($ 2010)

Connection Type	Revised price ($2010)	
	Business Hours	After Hours
New connection – single phase *JEN is the responsible person for metering*	340.45	406.67
New connection – three phase (less than 100 amps) *JEN is the responsible person for metering*	422.64	488.85
New connection – single phase *JEN is not the responsible person for metering*	340.45	406.67
New connection – three phase (less than 100 amps) *JEN is not the responsible person for metering*	422.64	488.85

Table 20-3: – Other fee based services ($ 2010)

Fee based services	Revised price ($, 2010)	
	Business Hours	After Hours
Manual energisation of new premises	11.77	36.30
Manual energisation existing premises	11.77	36.30
Manual de-energisation of existing premises	19.74	40.98
Adjust time switch	10.16	-
Manual special meter reads	7.99	-
Temporary disconnect and reconnect for non-payment	28.79	40.97
Connection—temporary supply (overhead supply—coincident abolishment)	359.92	419.65
Service vehicle visit	226.48	336.99
Wasted service truck visit—not JEN's fault	151.38	176.27
Fault response – not JEN's fault	246.84	289.15
Meter Test—single and multi phase meter installations with annual consumption of <160 MWh	236.88	300.24
Meter Test—Types 5 & 6 meter installation for first tier customers with annual consumption >160 MWh	236.88	300.24

Each year, JEN proposes to adjust the charges by (1+CPI) (1–X), where X reflects the escalation of cost inputs to the service in real terms. The relevant X factors are shown in Table 20-4 and Table 20-5.

20.6.2 Revised proposed X factors for fee based alternative control service prices

JEN's revised proposed X factors to apply to the fee based alternative control services for 2011 – 2015 regulatory period are set out in Table 20-4 and Table 20-5.

Table 20-4 – JEN's proposed X factors for fee based alternative control services (per cent)- Business Hours

No.	Fee based services - Business Hours	2011	2012	2013	2014	2015
1	New connection – single phase – *JEN is the responsible person for metering*	-2.61	-1.92	-2.07	-1.67	-1.56
2	New connection – three phase (less than 100 amps) – *JEN is the responsible person for metering*	-2.97	-1.43	-1.63	-1.20	-1.12
3	New connection – single phase – *JEN is not the responsible person for metering*	-2.61	-1.92	-2.07	-1.67	-1.56
4	New connection – three phase (less than 100 amps) – *JEN is not the responsible person for metering*	-2.97	-1.43	-1.63	-1.20	-1.12
5	Manual energisation of new premises	-1.93	-2.41	-2.54	-2.24	-2.04
6	Manual energisation existing premises	-1.93	-2.41	-2.54	-2.24	-2.04
7	Manual de-energisation of existing premises	-2.00	-2.52	-2.65	-2.33	-2.13
8	Adjust time switch	-2.21	-2.82	-2.92	-2.54	-2.34
9	Manual special meter reads	-1.93	-2.42	-2.55	-2.25	-2.05
10	Temporary disconnect and reconnect for non-payment	-1.94	-2.43	-2.55	-2.25	-2.05
11	Connection—temporary supply (overhead supply—coincident abolishment)	-2.24	-2.46	-2.57	-2.18	-2.04
12	Service vehicle visit	-2.18	-2.84	-2.92	-2.51	-2.34
13	Wasted service truck visit—not DNSP fault	-2.00	-2.61	-2.69	-2.32	-2.17
14	Fault response—not JEN's fault	-2.21	-2.88	-2.96	-2.54	-2.37
15	Meter Test—single and multi phase meter installations with annual consumption of <160 MWh	-1.87	-2.33	-2.46	-2.18	-1.98
16	Meter Test—Types 5 & 6 meter installation for first tier customers with annual consumption >160 MWh	-1.87	-2.33	-2.46	-2.18	-1.98

Table 20-5: JEN's proposed X factors for fee based alternative control services (per cent) – After Hours

No.	Fee based services – After Hours	2011	2012	2013	2014	2015
1	New connection – single phase – *JEN is the responsible person for metering*	-2.55	-2.07	-2.22	-1.82	-1.70
2	New connection – three phase (less than 100 amps) – *JEN is the responsible person for metering*	-2.87	-1.62	-1.81	-1.39	-1.30
3	New connection – single phase – *JEN is not the responsible person for metering*	-2.55	-2.07	-2.22	-1.82	-1.70
4	New connection – three phase (less than 100 amps) – *JEN is not the responsible person for metering*	-2.87	-1.62	-1.81	-1.39	-1.30
5	Manual energisation of new premises	-1.84	-2.28	-2.41	-2.14	-1.94
6	Manual energisation existing premises	-1.84	-2.28	-2.41	-2.14	-1.94
7	Manual de-energisation of existing premises	-1.89	-2.36	-2.49	-2.21	-2.01
8	Adjust time switch	0.00	0.00	0.00	0.00	0.00
9	Manual special meter reads	0.00	0.00	0.00	0.00	0.00
10	Temporary disconnect and reconnect for non-payment	-1.89	-2.36	-2.49	-2.21	-2.01
11	Connection—temporary supply (overhead supply—coincident abolishment)	-2.29	-2.58	-2.68	-2.28	-2.13
12	Service vehicle visit	-2.30	-2.99	-3.07	-2.64	-2.46
13	Wasted service truck visit—not DNSP fault	-2.08	-2.71	-2.79	-2.40	-2.24
14	Fault response—not JEN's fault	-2.26	-2.94	-3.02	-2.59	-2.42
15	Meter Test—single and multi phase meter installations with annual consumption of <160 MWh	-1.85	-2.31	-2.44	-2.16	-1.96
16	Meter Test—Types 5 & 6 meter installation for first tier customers with annual consumption >160 MWh	-1.85	-2.31	-2.44	-2.16	-1.96

20.6.3 Revised labour charge out rates including X factors for quoted alternative control services

JEN has incorporated the AER's approved charge out labour rates ($2010) as set out in the AER's draft decision for quoted services for JEN in appendix O.3, Table O.14. JEN's revised proposed charge out rates for quoted alternative control services for the forth coming regulatory period is set out in Table 20.6. For example, approved charge out labour rate of $79.80 ($2010) multiplied by (1+ 2.54 per cent) results in $81.82 ($2011).

Table 20-6: Proposed revised labour charge out labour rates including X factor to apply to quoted service prices for the forthcoming regulatory control period

Year	2011	2012	2013	2014	2015
Unit rate per man hour – business hours ($ real 2010)	81.82	84.52	87.37	89.89	92.31
Unit rate per man hour – after hours ($ real 2010)	102.28	105.65	109.21	112.36	115.38
X (per cent)	-2.54	-3.29	-3.37	-2.89	-2.68

JEN proposes to apply the above labour rates to the following quoted services shown below:

- routine connections (customers above 100 amps)
- damage to overhead service cables caused by high loads—restoration of overhead service cables pulled down by transport vehicles transporting high loads
- high load escorts—lifting of overhead lines
- covering of low voltage mains and services
- rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting services
- supply enhancement at customer request
- elective underground service where an existing overhead service exists
- complex supply abolishment.

JEN will determine the charge for this service by applying the proposed labour unit rate per hour, with material and plant costs being passed onto customers at cost incurred by JEN.

21 Outcomes monitoring and compliance

- The AER proposes to establish a monitoring and compliance framework to monitor the outcome of the 2011–2015 distribution determination
- JEN has estimate the additional complianc costs it is likely to incur based on the AER's guidance provided in chapter 21 of the draft decision
- JEN looks forward to participating in the AER's consultation on the monitoring framework that it intends to establish.

21.1 Summary of AER's draft determination and decision

In its draft decision, the AER stated its intention to establish a framework to monitor the outcome of the 2011–2015 Victorian distribution determinations, and the Victorian DNSPs' service levels delivered to their customers.

The AER indicated that the financial measures will include measurements 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 customer service outcome measures will include the traditional performance indicators in quality and reliability of supply, providing timely service to customers; as well as the monitoring of low supply reliability areas, and DNSPs' performance in responding to major network events.

The AER specified that the required information will be collected annually through the issuing of a regulatory information notice (RIN) under section 28F (1) (a) of the NEL following the final Victorian distribution determinations.

The AER pledged that it will undertake further consultation[514] with relevant stakeholders to determine the final outcome measures for DNSPs to report against, and this will be done after the final Victorian distribution determinations.

21.2 JEN's response to AER's draft determination and decision

In section 21.1 of its draft decision[515] the AER states:

"It is proposed that the monitoring framework set out in this chapter will replace the existing annual reporting framework previously established by the ESCV for monitoring a DNSP's regulatory accounts and network performance indicators."

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[514] Draft decision, p. 907.

[515] Ibid.

Whilst the AER's intention is to replace the existing reporting requirement, it is not clear to JEN how this will be achieved, given the existing obligations arise from regulatory instruments issued by the ESCV under its powers.

In section 21.7 of its draft decision, the AER specifies the outcome monitoring measures that it intends to establish for monitoring the Victorian DNSPs' consistency with their 2011-2015 distribution determination. The intention of the section was to provide guidance on the initial scope of the monitoring measures.

JEN currently provides much of the information the AER has foreshadowed that it will require from DNSPs in the forth coming regulatory period. The information is provided via the following reports:

- Regulatory accounting statements
- Annual tariff submissions
- Distribution and transmission network planning reports
- Service performance KPIs (in accordance to the ESCV Service Information Specification for Victorian Electricity Distributors, 1 January 2009)
- Health card measures.

Even though the final form of the monitoring measures is not know as yet, JEN considers that the reporting requirements the AER intends to establish are significantly more onerous than that which currently exists. JEN believes that it will incur additional compliance costs when the monitoring framework is implemented. Costs of making changes to business reporting systems can be significant. Audit assurance process including audit reports comes at a cost.

JEN has estimated the following costs based on the AER's guidance notes in section 21.7 of the AER's draft decision.

Table 21-1: Estimate of compliance costs for establishing AER's proposed monitoring and compliance framework

Monitoring measures	Costs of making changes to business reporting systems	Cost of producing reports, audit assurance process including audit reports to comply with RIN
	Capex ($'000)	Opex ($'000) pa
Financial reporting actual capex activities according to the building blocks, further separated into different network types (similar to those currently provided under the AER's RIN) actual opex activities according to the building blocks, further separated into different network types (or other suitable sub-categories), similar to those currently reported in the AER's RIN	Costs in the 1st year: Setup fields consistent with RIN in SAP - $80,000 Setup SAP reports - $20,000 Costs in 2nd year: Further improvements to SAP including additional reports - $30,000	Run reports in SAP, reconcile and produce final monthly report – $28,000 Annual Reports including regulatory review - $8,400 Review by auditor - $10,000
Capacity utilisation Condition of assets - Information reflecting the health (or condition) of each zone substation transformer and major item of switchgear	Nil	Prepare reports for RIN - $3,600 (Note this does not include data extraction, review as these are not additional activities).
Annual failure rate forecast for each asset category and against each failure category, taking into account planned investment over the period Annual out-turn failure rates reported on a normalised (per unit) basis	System modification to set up data capture and reporting - $30,000	Resource for auditing quality of failure data plus data entry into the IT system - $10,000
DNSPs must submit to the AER an annual report on their expenditure under the demand management incentive allowance	Nil	Prepare report including review - $5,000
JEN Board/CEO certification of RIN - approval process		$ 10,000

JEN estimates the likely additional compliance costs to be:

- One of capex cost of $106,000

- Annual opex cost of $75,000.

JEN has included the above additional costs in its forecast capex and opex step changes in Appendix 7.2. JEN requests the AER to provide an allowance in the final decision to account for the additional likely compliance costs that JEN has discerned section 21.7 of its draft decision.

JEN looks forward to participating in the AER’s consultation on the monitoring framework that it intends to establish for DNSPs to report against.

Glossary

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACS	Alternatove Control Services
Access Economics	Access Economics Pty Ltd, ACN 123 967 966
ACIL Tasman	ACIL Tasman Pty Ltd, ACN 102 652 148
ACIL Tasman report	ACIL Tasman, Review of Demand Forecasts for the AER
ACR	automatic circuit recloser
AEMC	Australian Energy Markets Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	Australian Gas Light Company
AGL Electricity	AGL Electricity Limited (now Jemena Electricity Networks (Vic) Ltd)
AIMRO	advanced interval meter roll out
AMA	asset management agreement between JEN and JAM
AMI	advanced metering infrastructure
AWE	average weekly earnings
AWOTE	average weekly ordinary time earnings
BBRR	building block revenue requirement
CAIDI	customer average interruption duration index
capex	capital expenditure
CAPM	capital asset pricing model
CFC	Construction Forecasting Council
COS	cost of service
CPI	consumer price index
CPRS	carbon pollution reduction scheme
current regulatory control period	current regulatory control period 1 January 2006 to 31 December 2010
DECC	Department of Energy and Climate Change (UK)
DMIS	demand management incentive scheme
DNSP	distribution network service provider

draft determination	Australian Energy Regulator, Victorian electricity distribution network service providers - Distribution determination 2011-2015
DRP	debt risk premium
DUOS	distribution use of system
EBA	enterprise bargaining agreements
EBIT	earnings before interest and tax
EBS	Enterprise Business Services
EBSS	efficiency benefit sharing scheme
EDC	Victorian Electricity Distribution Code
EDL	Electricity Distribution License
EGW	electricity, gas and water
EGWWS	electricity, gas, water and waste services division
ES&L	environmental safety & legal
ESCV	Essential Services Commission of Victoria
ESF	enterprise support functions
ESMS	electricity safety management scheme
ESV	Energy Safe Victoria
ETS	emissions trading scheme
EWOV	Energy and Water Ombudsman of Victoria
Forthcoming regulatory control period	regulatory control period 1 January 2011 to 31 December 2015
GAAR	Gas Access Arrangement Review
GCSS	guaranteed customer service level standards
GIS	geographic information system
GSL	guaranteed service level
GSP	gross state product
GWh	gigawatt hour
IEEE	Institute of Electrical and Electronics Engineers
IHD	in-home display
IT	information technology
ITP	IT Plan
JAM	Jemena Asset Management Pty Ltd (ACN 086 013 461)
JEN	Jemena Electricity Networks (Vic) Ltd, ACN 064 651 083 (ABN 82 064 651 083)

LPI	labour price indices
MAIFI	momentary average interruption frequency index
MAIFIe	momentary average interruption frequency index event
MCE	Ministerial Council on Energy
MED	major event day
MEPS	mandatory energy performance standards
MGH	
MRP	market risk premium
MTR	maximum transmission revenue
MW	megawatt
NAMP	network asset management plan
NCC	National Competition Council
NECF	national energy customer framework
NEL	National Electricity Law
NEMMCO	National Electricity Market Management Company Limited
NERA	National Economic Research Associates
NFACO	non-field activities and corporate overheads
NGER	national greenhouse and energy reporting
NGL	National Gas Law
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NPV	net present value
O&M	operating and maintenance expenditure
opex	operating expenditure
PB	Parsons Brinckerhoff
POE	probability of exceedence
previous regulatory control period	previous access arrangement period 1 January 2001 to 31 December 2005
PTRM	post tax revenue model
PwC	PriceWaterhouseCoopers
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RET	renewable energy target
RIN	regulatory information notice issued on 4 June 2010

RIN templates	templates required to be provided under the RIN
RIS	regulatory impact statement
RPQM	reliability and power quality maintained
Rules	National Electricity Rules
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SKM	Sinclair Knight Mertz
SMP	Service Model Project
SORI	Statement of Regulatory Intent
SPIAA	SPI (Australia) Assets Pty Ltd
STPIS	service target performance incentive scheme
TMED	major event day threshold
TOU	time of use
TUOS	transmission use of system
TWI	trade weighted index
UED	United Energy Distribution
VENCorp	Victorian Energy Network Corporation
VIC	Victoria
WACC	weighted average cost of capital
WAPC	weighted average price cap
WOBCA	whole of business cost allocation
ZSS	zone substation

Appendices

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1.1	Statutory Declaration under Section 28M(d) of the National Electricity (Victoria) Law	Public
1.2	Notes on amended form of statutory declaration	Public
1.3	Certification of reasonableness of key assumptions that underlie capex and opex forecasts	Public
2.1	RIN Templates for AER service classification	Confidential
2.2	Explanatory notes to templates	Confidential
3.1	JEN’s reference to AER’s concerns raised in its Draft Decision - Arrangements for Negotiations	Public
3.2	Negotiating Framework with AER amendments - clean copy	Public
3.3	Negotiating Framework with AER amendments - marked up copy	Public
4.1	JEN's reference to AER's concerns raised in its Draft Decision - Control Mechanisms for standard control services	Public
4.2	Price control worked examples	Public
4.3	Distribution tariffs classes for the 2010 calendar year (exclusive of GST)	Public
4.4	JEN’s proposed pass through control mechanism	Public
5.1	JEN's reference to AER's concerns raised in its Draft Decision - Growth Forecast	Public
5.2	NIEIR: Electrical sales and customer number forecasts to 2019 for the JEN electricity region	Public
5.3	NIEIR: Maximum summer demand forecasts for Jemena Electricity Networks to 2020	Public
5.4	NIEIR: Overview of economic and energy forecasting methodologies used at the National Institute of Economic and Industry Research, April 2010	Confidential
5.5	Frontier Economics: Review of NIEIR’s methodology for forecasting electricity consumption - Prepared for Citipower	Public
5.6	Frontier Economics: Review of policy adjustments – A report prepared for Citipower	Public

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5.7	Frontier Economics: Review of ACIL Tasman recommendations, a report prepared for CitiPower, June 2010	Public
5.8	Replacement of NIEIR AMI adjustment with Frontier Economics	Public
5.9	Reconciliation of JEN substation forecasts with NIEIR	Public
5.10	JEN load demand forecast methodology	Public
6.1	JEN's reference to AER's concerns raised in its Draft Decision - Outsourcing and related party margins	Public
6.2	Rapisarda witness statement - 6 Jul 2010	Confidential
6.3	SMP AMA Board Paper - 25 Nov 2009	Confidential
6.4	Service Model Project – Project Charter – 21 Jan 2009	Confidential
6.5	Presentation to AER on SMP - 4 Nov 2009	Confidential
6.6	Pitcher Partners - JGN Probity Plan - 5 Feb 2009	Confidential
6.7	Martin McCurry Witness Statement—16 July 2010 with JAM letter to the AER of 24 November 2009	Confidential
6.8	Evans & Peck - Industry stand margins	Confidential
6.9	Napier Blakely - Jemena Gas Networks (NSW) access arrangements 2010, Expert terms of reference – CAPEX review, Expert report and opinion	Confidential
6.10	Letter to JGN including Attachment 1	Confidential
6.11	UMS: Jemena Electricity Networks (JEN) – Victoria AUS, Operating Expenditure Efficiency Review, 15 July 2010	Public
6.12	Application of the outsourcing assessment framework for the JEN-JAM AMA	Confidential
7.1	JEN's reference to AER's concerns raised in its Draft Decision - Forecast opex including escalators, opex step changes, insurance	Public
7.2	Step changes	Confidential
8.1	JEN's reference to AER's concerns raised in its Draft Decision - Forecast capex including escalators, equity raising costs	Public

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8.2	PB: JEN Forecast Asset Replacement Volumes	Public
8.3	SKM: Victorian Distribution Network Service Providers cost escalator updates - 8 July 2010	Confidential
8.4	BIS Shrapnel: Review of Access Economics' Utilities Wage Model	Public
8.5	BIS Shrapnel: Wages Outlook for the Electricity Distribution Sector in Victoria	Public
8.6	KPMG Econtech: Assessment of the AER's Draft Determination on Labour Cost Escalators	Public
8.7	KPMG Econtech: Labour Cost Forecasts for Powercor and CitiPower	Public
8.8	JEN Capital Plan - SPIAA board paper & extract of resolution	Confidential
8.9	JEN's IT Program	Public
8.10	Business Case - Refurbishment of Pascoe Vale (PV) Zone Substation	Confidential
8.11	Business Case - Tullamarine (TMA) Zone Substation	Confidential
8.12	Strategic Planning Paper - KTS-MAT-AW-PV-KTS Sub-transmission loop	Confidential
8.13	Strategic Planning Paper - Somerton (ST) Zone Substation Supply Area	Confidential
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8.18	Business Case - Feeder Reconfiguration for YTS (Yarraville) retirement	Confidential

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8.19	Strategic Planning Paper - -Pole Top Structure Replacement Program	Confidential
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8.21	Strategic Planning Paper - Underground Cable Replacement	Confidential
8.22	Strategic Planning Paper - Overhead Conductor Replacement Program	Confidential
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8.24	Strategic Planning Paper - Zone Substation Transformer Replacements	Confidential
8.25	Strategic Planning Paper - Zone Substation Circuit Breaker Replacements	Confidential
8.26	Strategic Planning Paper - Pole Top Fire Mitigation	Confidential
8.27	Strategic Planning Paper - Automatic Circuit Recloser (ACR) and Remote Control Gas Switches (RCGS)	Confidential
8.28	Strategic Planning Paper - Reactive Fault Mitigation	Confidential
8.29	Strategic Planning Paper - Superceded Supervisory Cable Retirement Plan 2010 - 2015	Confidential
8.30	Strategic Planning Paper - Public Lighting Switch Wire Removal	Confidential
8.31	Strategic Planning Paper - GFN (Ground Fault Neutralisation) & SWER (Single Wire Earth Return)	Confidential
8.32	Strategic Planning Paper - Power Quality	Confidential
8.33	Strategic Planning Paper - Reactive Compensation at Point of Connections	Confidential
8.34	JEN Vegetation Management - Opex and Capex Step Change	Confidential
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8.38	JEN Broadmeadows depot replacement project - Feasibility Report	Confidential
9.1	JEN's reference to AER's concerns raised in its Draft Decision - Opening asset base	Public
9.2	Comments on AER RAB Roll Forward model	Public
9.3	AGLE Financial Model Final Decision	Confidential
10.1	JEN's reference to AER's concerns raised in its Draft Decision - Depreciation	Public
11.1	JEN's reference to AER's concerns raised in its Draft Decision - Cost of capital	Public
11.2	CEG: Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates - A report for Victorian Electricity DBs	Public
11.3	CEG: Detailed application of AER cost of debt methodology to alternative bond samples - A report for Victorian DBs	Public
11.4	CEG: Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates - A report for Country Energy	Public
11.5	CEG: Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008	Public
11.6	PricewaterhouseCoopers: Methodology for the calculation of debt risk premium	Public
11.7	PricewaterhouseCoopers: Letter to JGN: Re: Update of cost of debt methodology analysis in light of the AER's ActewAGL decision	Public
11.8	PricewaterhouseCoopers: Jemena Gas Networks (NSW) - The benchmark cost of debt for a gas distributor	Public
11.9	JEN WACC model	Confidential
11.10	PwC - Victorian Distribution Businesses, Methodology to Estimate the Debt Risk Premium	Public
11.11	Australian Energy Regulator, Final decision, Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 - 30 June 2015	Public
11.12	Professor Bob Officer & Dr Steven Bishop: Market Risk Premium - Comments on the AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers	Public

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11.13	Officer and Bishop: Market Risk Premium, Estimate for 2011-2015	Public
12.1	JEN's reference to AER's concerns raised in its Draft Decision - Taxation	Public
12.2	Neville Hathaway: Comment on: “A Measure of the Efficacy of the Australian Imputation Tax System” by John Handley and Krishan Maheswaran	Public
12.3	Neville Hathaway: Imputation Credit Redemption - ATO data 1988-2008	Public
12.4	Neville Hathaway & Bob Officer: The Value of Imputation Tax Credits – Update 2004	Public
12.5	Robert R. Officer: Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA’s Advisers	Public
12.6	Strategic Finance Group: Issues relating to the estimation of gamma - Report prepared for CitiPower, Jemena Electricity Networks, Powercor, SP AusNet and United Energy Distribution	Public
12.7	SFG: Response to AER Draft Determination in relation to gamma – Report prepared for ETSA Utilities	Public
12.8	Damien Cannavan, Frank Finn, Stephen Gray: The Value of Dividend Imputation Tax Credits in Australia	Confidential
12.9	SFG: Further analysis in response to AER Draft Determination in relation to gamma – Prepared for ETSA Utilities	Public
12.10	SFG: Market practice in relation to franking credits and WACC: Response to AER proposed revision of WACC parameters - Report prepared for ENA, APIA, and Grid Australia	Public
12.11	Skeels: Response to Australian Energy Regulatory Draft Determination	Public
12.12	Neville Hathaway: Practical Issues in the AER Draft Determination	
12.13	Skeels: Response to AER Questions – A report prepared for ETSA Utilities	Public
12.14	Skeels: A Review of the SFG Dividend Drop-Off Study – A Report prepared for Gilbert and Tobin	Public
12.15	Beggs and Skeels: Market Arbitrage of Cash Dividends and Franking Credits	Confidential
12.16	NERA: New Gamma Issues Raised by AER Expert Consultants, A report for JGN	Public

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12.17	NERA: Payout ratio of regulated firms, report for Gilbert and Tobin	Public
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12.20	GasNet Australia decision, 23 Dec 2003	Public
12.21	Handely and Maheswaran: A measure of the efficacy of the Australian imputation tax system	Confidential
12.22	Feros: Review of WACC parameters - Gamma, ETSA Price Reset	Public
12.23	Synergies: Gamma - New Analysis Using Tax Statistics	Public
12.24	Monkhouse: Adopting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System	Confidential
12.25	Monkhouse: The cost of equity under the Australian dividend imputation tax system	Confidential
12.26	ETSA Submission, Revised Regulatory Proposal 2010–2015	Public
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12.28	Handley: Report prepared for the AER on the estimation of gamma	Public
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12.30	Officer: The cost of capital of a company under an imputation tax regime system	Confidential
12.31	SFG: The value of imputation credits as implied by the methodology of Beggs and Skeels (2006)	Public
12.32	SFG: The impact of franking credits on the cost of capital of Australian firms	Public
12.33	Skeels: Estimation of γ	Public
12.34	Handley: Further Comments on the Valuation of Imputation Credits	Public
12.35	Handley: Memorandum to AER: Advice on Gamma in Relation to the 2010-2015 Qld/SA Electricity Distribution Determinations	Public
12.36	Handley: A Note on the Valuation of Imputation Credits	Public
12.37	NERA: AER's Proposed WACC Statement—Gamma: A report for the Joint Industry Associations	Public

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12.38	Field: Cost of Capital equations under the Australian imputation credit system	Public
12.39	Dempsey and Partington: Cost of Capital equations under the Australian imputation credit system	Confidential
12.40	Bellamy and Gray: Using stock Price Changes to Estimate the Value of Dividend Franking Credits	Public
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12.42	Breakthrough Agreement with Industry on Improvements to Resources Taxation, joint media release from the Treasurer, Prime Minister and Minister for Resources and Energy	Public
13.1	JEN's reference to AER's concerns raised in its Draft Decision - Efficiency carryover amounts fro 2006-10	Public
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