Rule Change Requests Relating to Economic Regulation of Network Service Providers

Submission from

Jemena Limited

to the

Australian Energy Market Commission

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Table of contents

1 Executive summary

The national electricity rules (**NER**) and the national gas rule (**NGR**) encapsulate some very good elements of incentive regulation as policy makers and the Australian Energy Market Commission (**AEMC**) intended when they were put in place a few years ago.

Jemena Electricity Networks (**JEN**) and Jemena Gas Networks (**JGN**) have both completed prices reviews under the new rules with the Australian Energy Regulator (**AER**). This process has been a substantial learning process for the businesses, the AER and stakeholders. The rules and our regulatory practice have been tested, and the body of knowledge we have developed is valuable.

JEN and JGN are both investing and operating efficiently in response to their regulatory incentives. Their capacity to continue to do that is dependent on the stability of the rules and the investment certainty they create. Accordingly, we encourage the AEMC to apply a very high threshold before adopting any changes to the rules that have been in place only a short time—that threshold being whether a major problem with the current rules has been clearly established.

Electricity distribution prices are rising. There is strong evidence to show that these price rises are the result of increased costs driven by the need to replace aging asset, meet growing demand, and maintain reliability. There is no evidence to show that these price rises are due to inadequacies of the current rules.

That is not to say that there is no scope to improve the rules or their application. Jemena supports changes to the regulatory process set out in the rules to provide more time and opportunities for the AER, network businesses and other stakeholders to actively contribute to the price review process. We also support enhancements to the debt risk premium rules and to capital expenditure incentives.

The most beneficial improvements we can see go beyond the rules themselves. They are improvements to increase stakeholders' confidence in rules outcomes.

Firstly, Jemena strongly supports better resourcing for consumer groups so they can be more a part of the price review process from start to finish, have a much deeper level of understanding of the issues, and provide meaningful input into the AER's decisions being made on consumers' behalf.

Secondly, we support the AER and businesses learning from the recent price reviews, building their capability and expertise, refining their practices, exchanging their insights, and embracing the challenges of this new regime.

2 Introduction

2.1 Context of this consultation

On 29 September 2011, the AER submitted two rule change requests to the AEMC in relation to the economic regulation of electricity and gas transmission and distribution businesses. These were:

- National Electricity Amendment (Economic regulation of network service providers) Rule 2011, relating to the economic regulation of electricity transmission and distribution businesses, and

- National Gas Amendment (Price and revenue regulation of gas services) Rule 2011, relating to the determination of the rate of return for gas network businesses.

On 18 October 2011, the AEMC received a rule change request from the Energy Users Rule Change Committee (**EURCC**) (representing a group of large energy users) relating to the calculation of return on debt for electricity network businesses under chapters 6 and 6A of the National Electricity Rules (**NER**).

Given that AER and EURCC have raised issues in the rate of return rules on the same subject matter, the AEMC has decided the two rule change requests should be dealt with as a consolidated request.

2.2 Jemena's network businesses

Jemena owns two network businesses upon which the AER's and the EURCC's proposed changes to chapter 6 of the NER and to part 9 of the National Gas Rule (**NGR**) would have a material effect.

This submission sets out Jemena's response those changes and reflects our experience during our recent price reviews and merits reviews.

Jemena Electricity Networks (Vic) Limited

JEN is a distribution network service provider (**DNSP**) that serves 320,000 consumers in north western Melbourne.

The AER regulates JEN's revenues and prices under chapter 6 of the NER. On 29 October 2010, the AER released its final revenue determination[1] for JEN's current regulatory control period—1 January 2011 to 30 December 2015. JEN sought merits review of aspects of the AER's determination and is awaiting the outcome of this merits review from the Australian Competition Tribunal (**Tribunal**), which is expected in early 2012.

Jemena Gas Networks (NSW) Limited

JGN is a covered pipeline service provider that serves 1,100,000 consumers in Sydney, Newcastle, Central Coast and Wollongong and over 20 regional centres across NSW.

The AER regulates JGN's access arrangement (which incorporates JGN's revenue, pricing and services) under parts 8, 9 and 10 of the NGR. On 11 June 2010, the AER released its final access arrangement determination[2] for JGN's current regulatory period—1 July 2010 to 30 June 2015. JGN sought merits review of aspects of the AER's determination and the Tribunal handed down its determination in respect of this review on 30 June 2011[3].

2.3 Structure of Jemena's submission

Jemena submission responds to both the AER's and the EUAA's rule change proposals. It follows the five broad subject areas identified in the AEMC's consultation paper[4]:

- **The capital and operating expenditure framework in electricity**, including restrictions on when the AER may reject an electricity network business's capital or operating expenditure forecast

1 AER, *Final, Jemena Electricity Networks (Victoria) Ltd, Distribution determination 2011–2015*, October 2010 <http://www.aer.gov.au/content/item.phtml?itemId=740828&nodeId=f90d8ff7117d5b3d659e219b68f9a880&fn=Victorian%20distribution%20determination%20final%20decision%202011-2015%20-%20JEN%20final%20determination.pdf>.

2 AER, *Final decision—Public Jemena Gas Networks Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015*, June 2010 <http://www.aer.gov.au/content/item.phtml?itemId=737314&nodeId=1ad7842f5a6f6ca1c7ca1818abf1bc95&fn=Final%20decision%20-%20public.pdf>.

3 Application by Jemena Gas Networks (NSW) Ltd (No 3) [2011] ACompT 6 (25 February 2011), Application by Jemena Gas Networks (NSW) Ltd (No 5) [2011] ACompT 10 (9 June 2011) and Australian Competition Tribunal, File No 5 of 2010, Determination, 30 June 2011.

4 AEMC, Consultation paper: *National Electricity Amendment (Economic regulation of network service providers) Rule 2011* and *National Gas Amendment (Price and revenue regulation of gas services) Rule 2011,* 20 October 2011, p. 2.

- **The incentive arrangements in electricity**, where the AER proposes that only part of actual capital expenditure incurred within a regulatory control period could be rolled into the asset base for the next period

- **The cost of capital provisions in both electricity and gas**, where the AER proposes an approach which most closely aligns with electricity transmission, and the EUAA proposes a new approach to the cost of debt

- **The efficiency of the regulatory process,** where the AER considers the regulatory process could be improved

- **Treatment of shared assets**, where the AER has proposed a new approach.

In relation to each area of rule change, Jemena has set out the current rules and addressed the AER's and EURCC's proposals under the AEMC "themes"[5]:

- **The problem**—We indicate whether we agree with the extent of the problems with the framework for economic regulation of electricity and gas networks as characterised by the AER and the EURCC. We provide views and analysis on the effectiveness of the current rules as they have been applied over the last five years.

- **Prescription and discretion**—We set out our view as to whether the proposed rules achieve the right balance between prescription and discretion. We note that rules that are more prescriptive set out more detail around the how the AER makes its decisions. Rules that allow for more discretion give the AER more scope to decide for itself how decisions are to be made.

- **AER's use of its discretion**—We note that, among other things, the AER's and the EURCC's proposed rules would give the AER greater or lesser discretion to assess and respond to regulatory proposals on a range of matters. We provide our view on whether the AER could achieve the same outcomes through greater use of the discretions it currently has, avoiding the need for expanding these discretions.

- **Costs and benefits**—We assess the costs and benefits of making the rule changes proposed by the AER and the EURCC, and comment on their

[5] AEMC (October 2011), p. 5.

justification for why their rule changes will better meet the national electricity objective (**NEO**) or national gas objective (**NGO**).

- **The solution**—On the basis of the problems raised by the AER and the EURCC, we indicate whether there are there any more preferable solutions to those problems. We note that the AEMC may only implement rule changes that respond to the problems raised by the AER, and it may not consider proposed changes that respond to other problems raised in submissions.

In addition, we comment on a number of issues specific to the EURCC's rule change proposal in relation to the cost of debt.

- **Claim of excessive profits to NSPs**—We comment on the excessive profit analysis presented in the EURCC's rule change request including the data on actual cost of debt estimates and indicate whether we disagree with the propositions put by the EURCC.

- **Government-owned NSPs vs privately owned NSPs**—We provide our views on whether the difference in debt raising costs of privately and government-owned NSPs should be taken into account in determining the return on debt element of an NSP's WACC.

- **Competitive neutrality and capital market discipline issues**—We comment on implications for competitive neutrality in the context of the Competition Principles Agreement arising from treating government-owned NSPs differently to privately owned NSPs.

Wherever possible, we have provided quantitative analysis or data to support propositions and positions in our submission.

Jemena's submission is complementary to and should be read in conjunction with the submission from the Energy Networks Association (**ENA**). Jemena endorses the ENA submission.

Before addressing each of the AER's proposed rule changes in detail, Jemena wishes to comment generally on the subject of effective incentive regulation.

3 Incentive regulation and its effect on prices

Key points:

- The role of incentive regulation in promoting economic efficiency for the long term interest of consumer is embedded in the revenue and pricing principles. It is a valuable component of our regulatory framework.

- Regulatory design and implementation have the potential to encourage dynamic efficiency through incentivising the right investment over the long term, or, alternatively, to distort investment and discourage dynamic efficiency. Dynamic efficiency is by far the most important determinant of long term benefits for consumers.

- Jemena's network businesses are operating efficiently because they are responding well to their incentives.

- Between 1996 and 2009 JEN significantly reduced its charges in real terms. Charges increased in 2010 due to the Victorian government-mandated roll out of smart meters. Despite that increase, distribution prices remain in real terms at a level similar to that of 1996.

- The anticipated increases in JEN's distribution charges in the 2011-15 regulatory period are driven by the growth in consumer connections and the increase in peak demand, as well as the higher costs of funding the consequential large-scale investment.

- It is therefore not clear how additional regulatory discretion is going to help reduce prices, unless that discretion is used to drive cost allowances and prices below efficient levels, which will not be in the long term interests of consumers.

3.1 The role of incentive regulation

3.1.1 National electricity and gas objectives

Jemena recognises and supports that any consideration of the NER and the NGR starts with the national electricity objective[6] (**NEO**) and the national gas objective (**NGO**)[7].

Box 1: NEO and NGO

The national electricity objective is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

The national gas objective is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

3.1.2 Revenue and pricing principles

The role and importance of incentive regulation is embedded in the NEL and the NGL through the revenue and pricing principles[8]. In addition to the NEO and the NGO, the principles are the cornerstone of chapter 6 the NER and of part 9 of the NGR. We've reiterated the revenue and pricing principles from the NEL in Box 2.

Box 2: Revenue and pricing principles

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

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

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in

[6] NEL, 7.

[7] NGL, 23.

[8] NEL, 7A and NGL, 24.

order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

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

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

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

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

(a) in any previous—

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

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

(b) in the Rules.

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

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

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

3.1.3 Aims of incentive regulation

Incentive regulation has developed over time as the best available tool for encouraging regulated businesses to act in a manner that mimics the outcomes of a competitive market. Policymakers and regulators achieve this by designing regimes that incorporate reward and penalty mechanisms, which take advantage of a firm's natural desire to maximise profit.

Economic theory tells us that, in most cases, competitive markets will deliver the best outcomes for both producers and consumers. However, in the case of natural monopolies, such as electricity and gas networks, competition is limited or absent.

At a high level, incentive regulation for utilities aims to:

1. ensure that consumers are charged no more than the reasonable cost of the services provided (limit wealth transfer from consumers to the firm)

2. encourage the firm to minimise the cost of service, and to provide an appropriate level of service (productive and allocative efficiency)

3. provide incentives for efficient investment in the regulated business (dynamic efficiency)

4. limit price discrimination (fairness in how each consumer group is treated).

3.1.4 Incentive regulation overcomes difficult challenges

Incentive regulation was also devised to deal with the fact that efficient costs cannot be forecast or determined by analysis. The proposition of incentive regulation is that a business will reveal its efficient costs in response to appropriately designed incentives. As Henry Ergas has said:

> A useful place to start is by reminding ourselves why incentives should play a major part in the design of regulatory arrangements. The simple reason for being concerned about incentives is that the information available to regulators is imperfect and asymmetrically distributed. If regulators knew all there was to be known – if the ACCC and its State counterparts were not only omnipotent but also omniscient – "command and control" methods would work perfectly well, as firms could be given production plans that maximised the sum of consumer and producer surplus. In the real world, of course, regulators do not know the most efficient production plans, nor the prices to which those plans would correspond. As a result, they must seek to ensure that regulated firms have the incentives to discover and implement those plans – a requirement which, in turn, implies that the firms' owners must obtain some gain from doing so.[9]

And Alfred Kahn has the following to say:

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[9] Ergas, H., (1999), *What is Regulatory Best Practice?*, Comments at the ACCC Conference on Incentive Regulation, Coogee Beach. <http://www.greenwhiskers.com.au/papers_reports/papers_ergas_regulatory_99.pdf>

> Regulation has an inherent tendency to place its principal reliance on (1) the decisions of its monopolist chosen instrument and (2) its own controls. In this division of responsibilities, it is also inherent in the institution that management proposes and the commission disposes. It could hardly be otherwise. The decision-making unit is the private corporation itself; it is private management, using private capital, that must initially determine the quality of service, the level of capacity, efficiency, and the rate at which all of these are improved. Typically – but by no means universally, as we shall see – the initiative must be private.
>
> In these circumstances, the central institutional questions have to do with the nature and adequacy of the incentives and pressures that influence private management in making the critical economic decisions.[10]

These summations remain valid today.

Earlier this year, before submitting its rule change proposals, the AER spoke about what it sees as the shortcomings of existing arrangements and what it is seeking to achieve through its proposed rule changes[11]:

> The inevitable consequence [of existing arrangements] is an outcome that is not a central estimate of efficient costs, or even one which would conservatively provide 'at least' efficient costs, but one which is biased in favour of the service provider and can lead to excessive payment by users.

and

> The AER considers that, in order to achieve the [National Electricity] objective, it is necessary that the rules allow the regulator to determine an unbiased estimate of efficient costs required to provide these services.

and

> If accepted, the changes we will propose will determine an unbiased forecast of efficient costs, while allowing certainty for businesses to respond to changing conditions. We will also propose stronger incentives on businesses to not overspend and to shield customers from inefficient excessive expenditure.

The inference to be drawn from these statements is that the AER expects allowances under its proposed rules to be lower than they would be if the rules were unchanged.

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[10] Alfred E Kahn, *The Economics of Regulation: Principles and Institutions*, MIT Press, 4th Ed, 1991, 47

[11] Reeves, A., 2011, *Finding the balance—the rules, prices and network investment*, Energy Users Association of Australia Energy price and market update seminar, 20 June 2011, Melbourne. <http://www.euaa.com.au/events/epmu/Presentations%202011/Reeves,%20Andrew.pdf>

However, the fact is that the efficient costs of operating a business cannot be forecast or determined with any precision by inspection or analysis. That is the case whether the aim is to produce an unbiased forecast of the level of prudent and efficient costs or the limits of the possible range of prudent and efficient costs.

3.1.5 The current rules encapsulate good incentive regulation

There are a number of examples of good incentive regulation as implemented under the current rules.

Electricity and gas distributors are encouraged to reduce their operating costs by being allowed to keep the savings for a small number of years. The reward is sufficient for firms to go ahead with cost saving initiatives. While the firms benefit, so does the consumer as lower efficient costs are revealed and used to set future cost recovery allowances.

Similarly, distributors are encouraged to reduce their capital expenditure by being able to keep within-period financing costs and depreciation on any under-spend. This helps ensure that businesses only build and replace assets when the spend is required. Having said that, there is scope for the incentives around capex to be improved. We discuss this further in section 5.

The service target performance incentive scheme for electricity distributors also encourages businesses to maintain and improve the reliability of their networks through a system of rewards and penalties.

To date, all of the above incentives have been underpinned by a stable regulatory regime, with relatively minor incremental changes.

3.2 Objective of economic efficiency

The overarching objective of the regulatory regime is economic efficiency for the long term interest of consumers. Whether in making and amending the rules (as is the task of the AEMC) or administering the rules (as is the task of the AER) it is important to consider the three dimensions of economic efficiency—productive, allocative and dynamic.

In thinking about the three dimensions of efficiency, there is a potential need to make trade-offs between them, and to consider the different impacts each can have on the long term interest of consumers. More importantly, one must also consider the relative competencies and different roles that the regulated business and the regulator can play in helping achieve overall efficiency.

Productive efficiency

The evolution of incentive-based regulation essentially recognised the fact that, while it is difficult for a regulator to determine the relative productive efficiency of regulated businesses in the absolute, the regulator can set incentives to ensure all businesses move towards the efficiency frontier over time by reducing the costs of production and revealing their actual efficient costs in the process. This recognises that it is the business that is best placed to drive productive efficiency, in response to incentives set by the regulatory regime.

Allocative efficiency

Allocative efficiency in the market for electricity distribution services is arguably not a significant issue, as the demand for a connection to the electricity grid is highly inelastic, even more so than demand for electricity itself. Network charges would need to be extremely high for a consumer to make the call, at the margin, that having a network connection is not worth the price. Similarly, it is difficult to imagine a situation where a consumer, that would otherwise stay off-grid, connects to the network simply because the price is very low.

Having said that, allocative efficiency in the market for gas distribution services is a significant issue because it competes with electricity and other energy sources for end uses.

Dynamic efficiency

The third dimension of efficiency—dynamic efficiency—is, in Jemena's view, by far the most important determinant of long term benefits for consumers, particularly in capital-intensive industries with long investment horizons. Dynamic efficiency is a measure of efficiency over the long term through innovation and the right investments being made at the right time. Regulatory design and implementation have the potential to encourage dynamic efficiency through incentivising the right investment over the long term, or, alternatively, to distort investment and discourage dynamic efficiency. Jemena considers that the largest gains or losses to consumers' interests will be made in this dimension of efficiency.

For example, timely investment in new technologies can unlock new services and benefits to consumers, whereas delayed investment can result in:

- unnecessarily higher operating and maintenance expenditure
- lower quality of supply

- eventually, higher costs of making the unavoidable, but inefficiently delayed investment at a later point in time when labour and material costs have increased.

In network infrastructure, dynamic efficiency is achieved when businesses have the right incentives to invest and are comfortable that the regime is stable and transparent enough to ensure that the long-lived investments made will yield a reasonable return over their life time, which, for regulated businesses is often a period of 50 years or more.

The stability of the regulatory regime is therefore a key determinant of whether dynamic efficiency will be achieved.

3.3 Importance of the rule change process to promote economic efficiency

The AEMC's decision on this rule change will be a precedent-setting decision with long term ramifications for investors' perceptions of the stability of the Australian regime.

The rule change process and the AEMC's role in that process have purposely been designed to ensure the transparency and stability of the regime. In effect, the AEMC acts as the guardian of the regime's stability and transparency. The precedent built up through the AEMC's decisions in accepting, amending or rejecting rule changes assists investors in understanding what thresholds must be met before regulatory change is introduced.

The process for and outcome of this rule change is particularly important, given that the current chapter 6 rules have only been in place for less than four years—less than a single regulatory period—and the NGR have been in place for a little over three.

In that time, a number of investors, including many private investors, have implemented large-scale capital expenditure programs for those businesses. Those investments were made on the expectation that the NER and NGR regimes will remain reasonably stable.

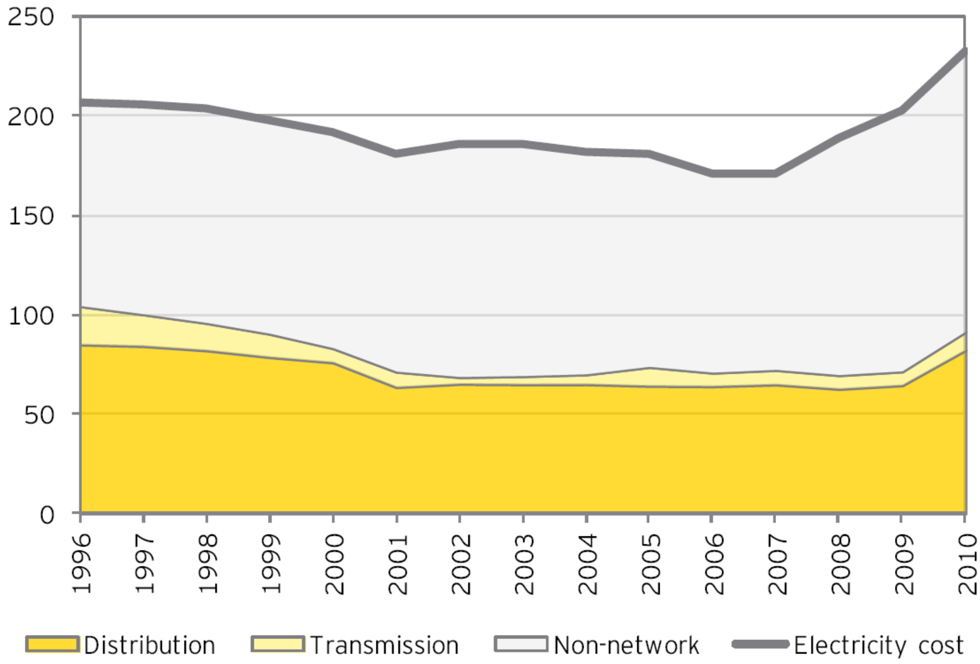
The AER's rule change proposal will be the first real test for that assumption.

3.4 Jemena Electricity Networks: a case study in responding to incentives

For the Jemena group the relative stability and success of the incentive regime that has been in place to date can be demonstrated through the performance of Jemena Electricity Networks (Vic) Limited (**JEN**).

As can be seen from Figure 1[12] below, between 1996 and 2009 JEN significantly reduced its charges in real terms. Charges increased in 2010 due to the Victorian government-mandated roll out of smart meters. Despite that increase, distribution prices remain in real terms at a level similar to that of 1996.

Figure 1: Jemena Electricity Networks: Electricity costs for an average residential consumer by component 1996 to 2010 ($ per MWh, real 2010)

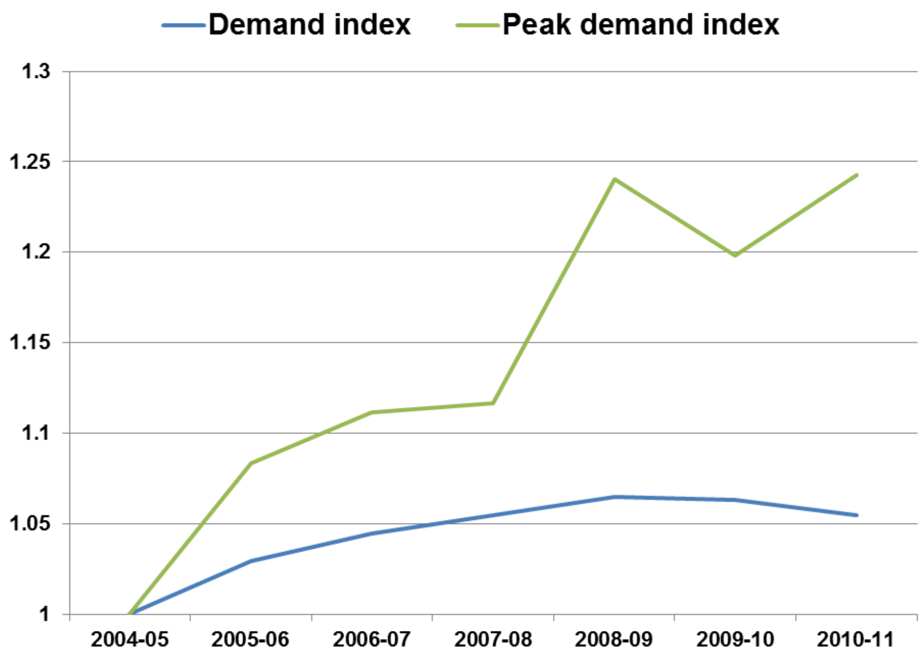


The anticipated increases in JEN's distribution charges in the 2011-15 regulatory period are driven by the growth in customer connections and the increase in peak demand, as well as the higher costs of funding the consequential large-scale investment. In particular, peak demand is rising faster than energy use, thereby

[12] Ernst and Young, *Victorian domestic electricity prices 1996-2010: the contribution of network costs*, A report for the Victorian electricity network businesses, 9 September 2011, Figure 13, p. 28.

increasing network costs per unit of electricity consumed by a customer. This is demonstrated by Figure 2 below.

Figure 2: Peak demand compared to energy demand



Source: AEMO Statement of Opportunities 2011

The impact of these factors is evidenced by the AER approving large scale increases in JEN's capital expenditure for customer connections and network reinforcement.[13]

JEN's approved net customer connection capital expenditure for 2011-15 is $43.5 million or 81 per cent higher than the actual spend in the 2006-10 regulatory period. Similarly, JEN's approved reinforcement capital expenditure is $33.2 million or 56 percent higher than historic spend. The overall increase approved by the

[13] AER, *Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, June 2010, Table 8.17 <http://www.aer.gov.au/content/item.phtml?itemId=736991&nodeId=1822051ac603ac047389b47cc147e492&fn=Victorian%20distribution%20draft%20decision%202011-2015.pdf>and

AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, Table 8.24. <http://www.aer.gov.au/content/item.phtml?itemId=740898&nodeId=c7b10ddc909d7b32f3d1a1687ce00767&fn=Victorian%20distribution%20determination%20final%20decision%202011%20-%202015.pdf>

AER to JEN's total net capex compared to historic levels is $106.3 million or 32 per cent.[14]

In support of their rule change proposals, neither the AER nor the EURCC has put forward evidence, or asserted, that JEN's or other Victorian distributors' costs to date have been inefficient.

On the contrary, Victorian cost levels are often held up as being the lowest in the Australian electricity distribution sector. It is therefore not clear how additional regulatory discretion is going to help reduce prices, unless that discretion is used to drive cost allowances and prices below efficient levels, which will not be in the long term interests of consumers.

[14] AER, *Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, June 2010, Tables 8.6, 8.17 and 8.19. <http://www.aer.gov.au/content/item.phtml?itemId=736991&nodeId=1822051ac603ac047389b47cc147e492&fn=Victorian%20distribution%20draft%20decision%202011-2015.pdf>and

AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, Table 8.24, 8.27 and 8.40. <http://www.aer.gov.au/content/item.phtml?itemId=740898&nodeId=c7b10ddc909d7b32f3d1a1687ce00767&fn=Victorian%20distribution%20determination%20final%20decision%202011%20-%202015.pdf>

4 The capital and operating expenditure framework in electricity

Key points:

- There is no case for the AER's proposed rule changes for opex and capex forecasting.
- The current operating and capital expenditure forecasting rules are operating well.
- The AER's proposed rule changes represent a fundamental shift to the current framework and would likely result in significant investment uncertainty.
- DNSPs already have incentives to not inflate their operating and capital expenditure forecasts and have responded to those incentives
- The AER already has sufficient discretion to amend operating and capital expenditure forecasts and regularly exercises that discretion.

4.1 The current electricity distribution rules

The NER currently requires the AER to accept DNSPs' proposals if it is *satisfied* that the forecasts *reasonably reflect* efficient, prudent and realistic expenditure[15]. The NER also requires that the AER *not* accept a forecast capital or operating expenditure amount in a DNSP proposal where the AER is not satisfied that the forecasts reasonably reflect that level of expenditure.[16]

In addition clause 6.12.3(f) of the NER requires that if the AER refuses to approve an operating expenditure (**opex**) or capital expenditure (**capex**) forecast, the substitute amount or value on which the distribution determination is based must be:

- determined on the basis of the current regulatory proposal

[15] NER, 6.5.6(c) and 6.5.7(c).

[16] NER, 6.5.6(d) and 6.5.7(d).

- amended from that basis *only to the extent necessary* to enable it to be approved in accordance with the NER.

There are also a number of operating and capital expenditure objectives and factors[17] that the AER must have regard to when deciding whether or not to approve a DNSP's forecast including:

- the information included in or accompanying the DNSP's proposal, which must comply with the requirements of a regulatory information notice the AER may issue
- submissions received in the course of consulting on the proposal
- analysis undertaken by or for the AER and published before it makes its final determination
- benchmark expenditure that would be been incurred by an efficient DNSPS.

4.2 The problem

4.2.1 AER's view of the problem

DNSPs have an incentive to, and do, inflate their forecasts

The AER proposal claims that, under the current rules, DNSPs have an incentive to propose the highest possible opex and capex forecasts among those that may be considered prudent and realistic, and that the burden is on the AER to prove those forecasts are not efficient. The AER claims that this has exposed consumers to the risk of systematically inflated forecasts.[18]

AER is required to deal with engineering detail

The AER submits that forecast proposals are currently based on a large amount of engineering detail and a "bottom up" calculation of the required expenditure. This requires the AER to conduct a line by line analysis in order to reduce the forecast to within the "reasonable" range.

The AER says this process is resource intensive and includes consideration of engineering details which may preclude the involvement of third party stakeholders

[17] NER, 6.5.6(a)(1)-(4), 6.5.6(e)(1)-(10), 6.5.7(a)(1)-(4) and.6.5.7(e)(1)-(10).

[18] AER, *Rule Change Proposal, Economic regulation of transmission and distribution network service providers – AER's proposed changes to the National Electricity Rules*, September 2011, pp. 27-28.

such as consumer groups. Further, the AER's proposal suggests that the AER has a pre-determined "reasonable" range that it must adjust expenditure to fit within[19].

AER's power to amend forecasts is unduly restricted

The AER says that its power under the NER to reject and/or substitute opex and capex forecasts is unduly restricted. This implies that the AER does not have sufficient discretion to amend DNSP opex and capex forecasts.

The AER submits that this is because it must have regard to the DNSP's regulatory proposal and it is limited in its ability to have regard to others factors such as benchmarking.

Obligation for AER to only consider analysis it has published

The AER submits that the current opex and capex factors that require it to publish analysis prior to its decision have the potential to make the decision making process unworkable within the prescribed timeframes. The AER claims this requirement creates a cycle of publishing analysis that creates opportunities for gaming and delay.[20]

4.2.2 Jemena's view of the AER's problem

The AER has not demonstrated that a material problem exists in the NER.

DNSPs have an incentive to lodge forecasts that comply with the rules

DNSPs have an incentive to lodge forecasts that meet the efficiency and prudence tests of the rules because, if they don't, the AER will reject them.

These incentives arise from the AER's capacity to discourage inflated forecasts by:

- using its information gathering powers to require a full disclosure of actual costs, forecasts costs, corporate and technical activity, and to require explanations of variances and substantiation of forecasts.

[19] AER, *Rule Change Proposal, Economic regulation of transmission and distribution network service providers – AER's proposed changes to the National Electricity Rules, Parts A and B*, 29 September 2011, p. 13.

[20] AER, *Rule Change Proposal, Economic regulation of transmission and distribution network service providers – AER's proposed changes to the National Electricity Rules, Parts A & B*, 29 September 2011, p. 38.

- requiring each DNSP's Chief Executive Officer to sign a statutory declaration that the forecasts of the regulatory proposal are true and correct to the best of their knowledge

- thoroughly assessing the DNSP's forecast in the light of that information.

Dealing with a level of engineering detail is required to implement our incentives

Jemena agrees with the AER that this is a resource-intensive exercise and there are good reasons why the AER needs to examine a reasonable level of technical detail when considering capex and opex forecasts.

The process of forecasting is by nature inherently technical. The incentive framework and the AER's ability to make skilful assessments of each DNSP's forecasts relies on:

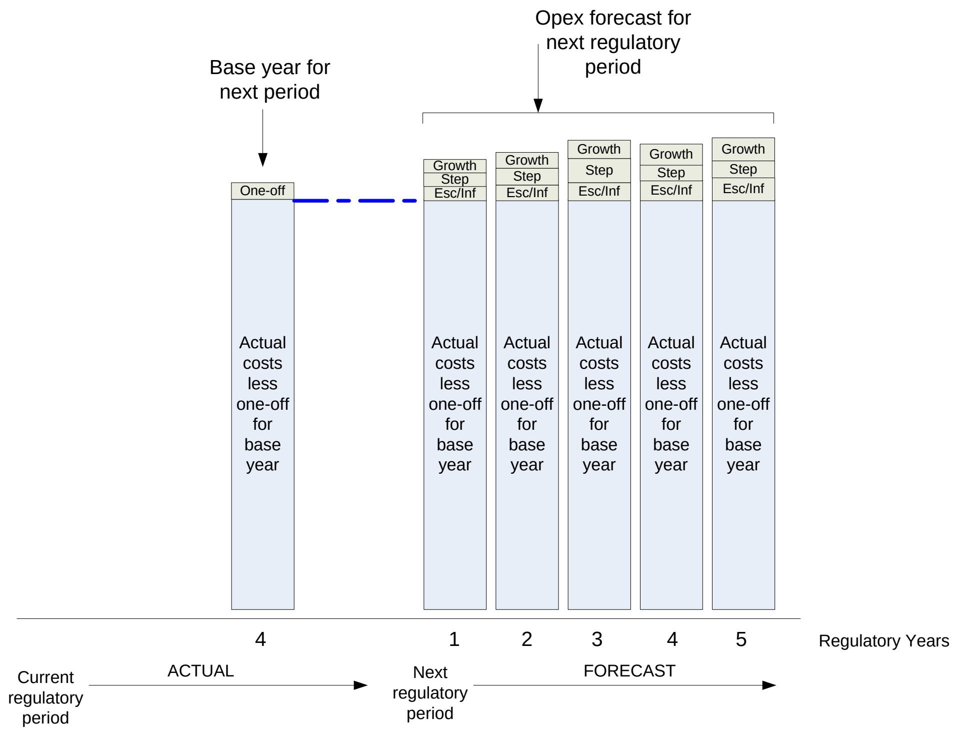
- each DNSP:
  - revealing to the AER the information the AER requests about the DNPS's actual costs and its operating and capital works activity over the current regulatory period as a reference point
  - exerting its considerable expertise to develop well-substantiated forecasts for the next regulatory period with full recognition of the history and potential of its network
- the AER having a good level of technical capability and skill to test those forecasts.

As the national energy industry-specific regulator the AER has been established to have the level of expertise necessary to do this.

The base year roll-forward method reduces considerably the technical detail the AER needs to examine to determine a DNSP's forecast opex. For this method the DNSP reveals its actual opex costs for a base year—the latest year in the current regulatory period for which actual costs are available—then proposes adjustments to it for one-off events, to determine its opex cost base. It then forecasts its opex in subsequent years by adding the incremental costs (or savings) that it expects to incur due to forecast network growth, step changes, escalation of input costs and inflation. Given the efficiency incentives in place during the base year, the AER may infer the base year costs are efficient and confine its detailed examination to the base year one-off costs, forecast network growth, step changes, escalation of input costs and inflation.

Figure 3 shows the base year roll-forward method in action.

Figure 3: Base year roll-forward method



For capex and the one-off costs, network growth, step changes, escalation and inflation associated with opex, the AER does need to examine the technical detail of a DNSP's proposed forecast expenditure to satisfy itself that it is prudent and efficient. Even so, with the judicious use of information requests, expert advisors, models, questioning and analysis, the AER has the opportunity to rigorously test each DNSP's proposal with increasing efficacy and efficiency. This is especially the case as the AER gains more experience with each review.

AER's power to amend forecasts is not unduly restricted

Jemena does not agree with the view that the AER's power under the NER to reject and/or substitute opex and capex forecasts is unduly restricted. The NER gives the AER sufficient discretion to disallow expenditure that is not prudent and efficient and that the AER has used it.

Jemena notes that in every distribution determination under the rules, the AER has employed its information gathering powers, carefully examined each DNSP's proposed opex and capex forecasts and rejected both. The AER has in each case substituted its own forecast of the total opex and capex expenditure it considers reasonably reflects the opex and capex criteria and factors[21].

In our analysis of our experience below, we provide several examples of the AER exercising this discretion in relation to JEN.

Obligation for AER to only consider analysis it has published

The AER has correctly highlighted in its submission that it is important stakeholders have an adequate opportunity to consider and respond to submissions the DNSPs make to the AER. It is equally important for robust decision-making that all stakeholders have an adequate opportunity to consider the data, approaches and expert reports upon which the AER intends to rely before its final determinations.

Accordingly, it is appropriate that the rules obligate the AER to publish and consult on the analysis conducted by or for the AER—not just in relation to opex and capex forecasting, but for all elements of its determination.

We explore that aspect of the AER's rule change proposal and the opportunity to redesign of the review process to accommodate better transparency and consultation in section 7 of this submission.

4.2.3 Analysis of the effectiveness of the current rules over the last five years

A review of recent AER decisions under the NEL, and JEN's in particular, demonstrates that the AER does have sufficient discretion to disallow and/or substitute opex forecasts to achieve the opex and capex forecasting objectives.

How the AER discouraged inflated forecasts

The AER already has and exercises its power to discourage JEN from lodging inflated forecasts.

It did this by:

- using its extensive information gathering powers to obtain the JEN's actual costs

[21] For a comprehensive review of the opex and capex forecasts put forward by DNSPs and the forecasts substituted by the AER in its final decisions see Table 4.1 of ENA expert report by NERA Economic Consulting, *AER's Rule Change Proposal – Decision-Making Test for Expenditure Forecasts*, December 2011.

- requiring CEO sign-off of JEN's regulatory information notice (**RIN**) responses by way of a statutory declaration

While the AER used its information gathering powers, its approach indicated that it is still becoming acquainted with electricity distribution businesses and what information is most useful for its purposes. Over the course of JEN's price review, the AER served JEN with 3 separate and large information requests. After an extended period of consultation and three drafts, the AER served JEN's first RIN on 14 October 2009, around 6 weeks before JEN was required to submit its response with its regulatory proposal in 30 November 2009. On 9 December 2009, the AER served JEN with a "capex guideline paper" seeking significant additional information and, on 4 June 2010, shortly before the AER draft decision, an urgent RIN. JEN's impression at the end of this process was that the AER sought a lot of information that was surplus to its needs and could have obscured an efficient evaluation of JEN's proposal.

JEN learnt from this process too. It endeavoured to provide information in its regulatory proposals that it believed would assist the AER with its evaluation of JEN's forecasts, along with complete RIN responses. JEN also assumes that the AER will receive better a well substantiated proposal and is continually seeking to improve its practice. Since its price review, JEN has sought the AER's feedback on the relevance, completeness, clarity, structure and timeliness of the information JEN provided.

In Jemena's view, improvements in information exchange process during price reviews have the potential to reduce the volatility between the AER's draft and final decisions. If businesses know better what information the AER's seeking well in advance, they will be able to provide that information readily with their regulatory proposals. If the AER has that information sooner, may not feel as unsatisfied and inclined to cut opex and capex forecasts in its draft decisions to the extent it has done. Markets and ratings agencies respond negatively to adverse draft decisions and removing that volatility would improve the environment for investors.

How the AER examined JEN's engineering detail

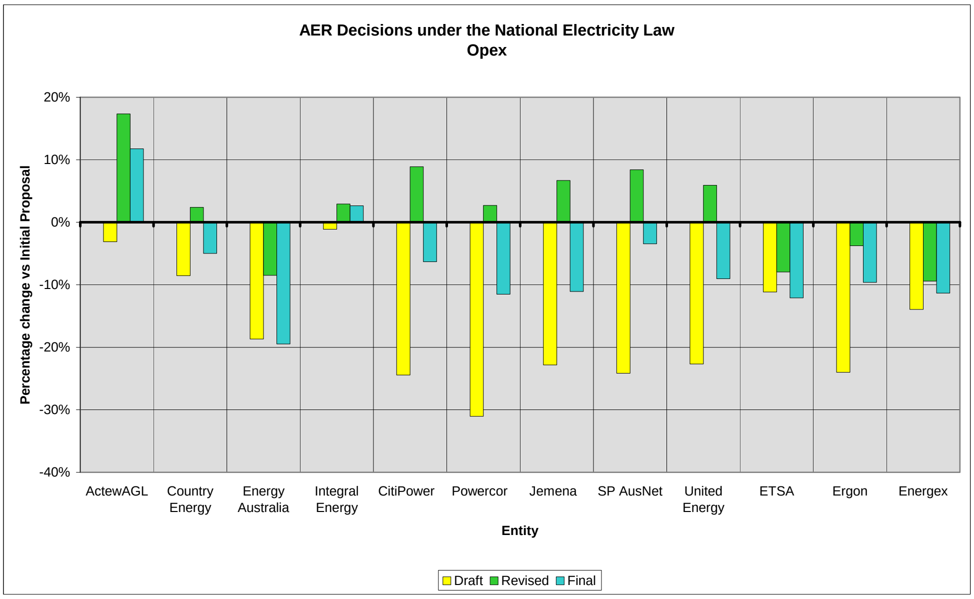
After JEN submitted its opex and capex forecasting both its original and revised regulatory proposals, as expected the AER thoroughly examined JEN's technical detail through engineering consultants the AER hired to review of our one-off costs, step changes, growth forecasts, programs and samples of projects. AER staff participated in this review, which involved the AER submitting to JEN over 100 technical questions.

The AER also conducted a detailed review of JEN's regulatory financial models and met with JEN several times to walk through and gain a better understanding of them.

How the AER exercised its discretion – opex forecasts

Figure 4 below shows that the AER is able to propose substantial cuts to all DNSP's opex programs at the draft decision stage during the recent round of reviews. In every case the AER has made overall opex cuts in their final decision with respect to the DNSP's revised proposals, not just 'line-by-line' adjustments. This clear pattern does not support the AER's view it is constrained or unable to exercise its discretion. In fact, it suggests the opposite.

Figure 4: AER opex decisions under the National Electricity Law



This is supported by the AER itself in its final decision for JEN[22]:

> The AER has considered each of the Victorian DNSPs' revised forecast opex proposals in accordance with opex factors in clause 6.5.6(e) of the NER. For the reasons discussed in this chapter the AER is not satisfied that each component of operating expenditure associated with the Victorian DNSPs' revised forecasts opex proposals forms a total opex forecast that reasonably reflects the opex criteria.

[22] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, p. 372.

An example of the AER exercising discretion with regard to JEN opex specifically is its exclusion of related party margins from forecast base opex. The AER's reasoning for this was that the related party margins did not "pass the presumption threshold", with the AER concluding that a margin above the related party's direct costs is inappropriate and does not form part of a total forecast opex that reasonably reflects the opex criteria[23]. This seems to be a clear example of the AER exercising its existing discretion without constraint.

The AER's central premise in its opex and capex forecasting rule change proposal is that it is required under the NER to accept expenditure forecasts which have been systematically inflated. Jemena notes that at no point in its decisions did the AER say or imply that it felt constrained in exercising its discretion. In fact the AER's language in its decisions suggests quite the opposite. For example in the Victorian DNSP determination, which included JEN, the AER stated that:

> The AER's decision requires it to be satisfied that the total of the forecast opex, not each individual program and project or element which constitutes that total forecast opex, reasonably reflects the operating expenditure criteria[24].

How the AER exercised its discretion – capex forecasts

Similar to opex, a review of recent AER decisions under the NEL demonstrates that the AER currently does have sufficient discretion to disallow and/or substitute capex forecasts. Figure 5 below shows that the AER is routinely able to propose substantial cuts to capex programs at the draft decision stage. Furthermore, as with opex, in every case the AER has made overall capex cuts in its final decision with respect to the DNSP's revised proposals. This clear pattern does not support a view that the AER is unnecessarily constrained or otherwise unable to exercise discretion in making its determination on forecast capex and opex amounts.

The AER appears to hold such a view in the JEN final decision[25]:

> ..the AER is not satisfied that Jemena's total capex allowance reasonably reflects the capex criteria, under clause 6.5.7(d) of the NER the AER must not accept the forecast capex proposed by Jemena. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of capital expenditure for each DNSP for the

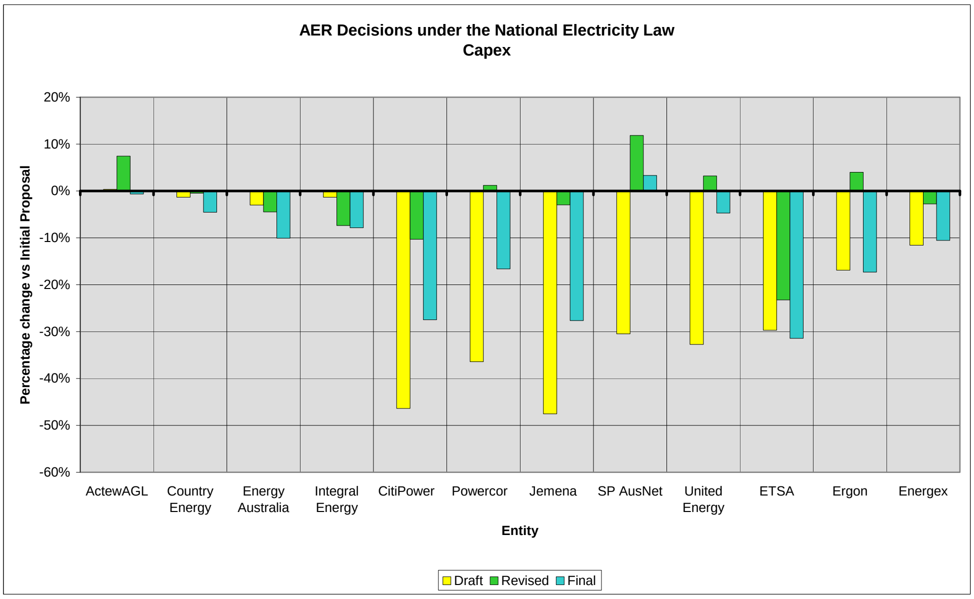
[23] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, p. 326.

[24] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, p. 312.

[25] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, p. 436.

forthcoming regulatory control period, which it is satisfied reasonably reflects the capex criteria, taking account of the capex factors.

Figure 5: AER capex decisions under the National Electricity Law



An example of the AER exercising its discretion in relation to capex forecasting is the disallowance of $98.7 million of replacement capex from JEN's capex forecast in its December 2009 regulatory proposal[26]. The AER reforecast replacement capex for all the Victorian DNSPs using a replacement capex forecasting model developed by its own consultants Nuttall Consulting in September 2009. The AER's reasoning for this was[27]:

> Given these issues, the AER also considers that the Victorian DNSPs' forecast capex does not support the NEO, as it is unclear on the evidence available whether this capex constitutes efficient investment in or efficient operation and use of, electricity services for the long-term services of consumers. Further, the AER also considers that the revenue and pricing principles are not satisfied. For example, in the absence of robust information, it cannot be determined whether the costs that will be incurred are efficient such that the Victorian DNSPs should have a reasonable opportunity to recover at least the efficient costs of complying with regulatory requirements, as set out in section 7A(2) of the NEL.

[26] JEN forecast $151.5 million replacement capex in its initial December 2009 proposal, the AER draft decision allowed $66.5 million, JEN's revised proposal forecast $159.1 million and the AER final decision allowed $52.8 million.

[27] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, p. 428.

This is an example of the AER exercising its existing discretion without undue constraint.

JEN's historical performance against its and the ESCV's forecasts - opex

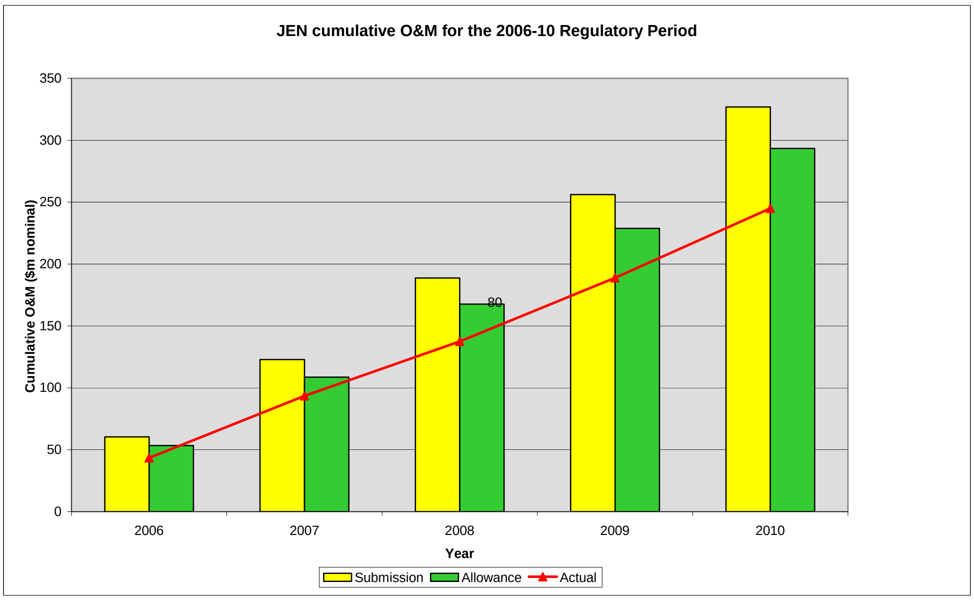
At a high level, the rules that the Essential Services Commission of Victoria's (**ESCV**) applied in 2005 to its determination of JEN's 2006-10 opex and capex forecasts and allowances were similar to that in the current NER.

Figure 6 below shows JEN's cumulative historical and estimated opex spend for the 2006-10 regulatory period compared to the ESCV allowance.

Rather than showing a trend for over-forecasting, the diagram illustrates that JEN was able to realise efficiencies in each year of the regulatory period. The extent of these realised efficiencies increased over the regulatory period.

This is consistent with the incentive framework encapsulated in the current rules that encourage DNSPs to reduce their opex by realising efficiencies as outlined in section 3 of this submission. JEN's actual costs for 2009 (adjusted for one-off costs) became the opex cost base for its 2011-15 opex forecasts.

Figure 6: Comparison of cumulative opex over 2006-10

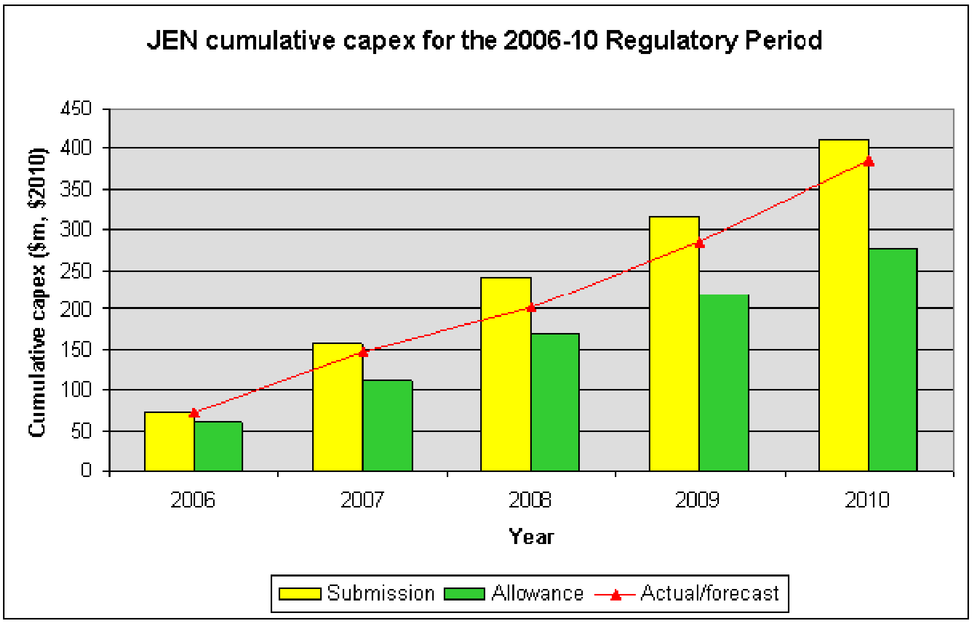


JEN's historical performance against its and the ESCV's forecasts - capex

Figure 7 below shows JEN's cumulative historical and estimated capex spend for the 2006-10 regulatory period compared to the ESCV allowance. The diagram clearly demonstrates that for the 2006-10 period, JEN consistently spent very close to its own forecast. This clearly demonstrates that JEN does not inflate its forecasts and is able to accurately forecast its capital expenditure.

Later in this submission at section 5, Jemena outlines factors that influence actual capex.

Figure 7: Comparison of cumulative capex over 2006-10



No evidence of a material problem with the rules

The AER has set out in its rule change proposal a number of problems it says exist in the current NER. These include that DNSPs systematically inflate their forecasts and that the AER's discretion to adjust these forecasts is unduly constrained.

Jemena's experience is that, under the current NEL and NER, the AER can discourage JEN from submitting inflated forecasts and has demonstrated its ability to review and adjust JEN's forecasts to level it believes are prudent and efficient.

Jemena does not consider the AER has been able to demonstrate there are material problems with the opex and capex forecasting rules as they are currently drafted that would justify making the changes that the AER proposes.

4.3 Prescription and discretion

4.3.1 AER's proposed rule change

In essence, the AER's proposal seeks to:

- provide that the AER is to determine the forecast opex that it considers would meet the efficient costs that a prudent DNSP would require to achieve the opex and capex objectives
- remove the requirement that the AER is to accept the DNSP's proposed opex or capex forecasts if the AER is satisfied the forecasts reasonably reflect the opex or capex criteria, as relevant
- amend the opex and capex factors to:
  - remove the AER's obligation to have regard to the factors listed in the NER and replace it with a discretion for the AER to have regard to any or all of them as it considers appropriate
  - remove, and in some cases re-introduce in an altered way, a number of factors from the list:
    - the information included in or accompanying the DNSP's proposal
    - submissions received in the course of consulting on the proposal
    - analysis undertaken by or for the AER and published before it publishes is final determination
  - amend a number of factors on the list as consequences of the AER's other proposed rule changes, in relation to:
    - incentive schemes
    - non-network alternatives

- retain a number of factors to the list:
  - benchmark expenditure
  - expenditure during the preceding regulatory period
  - relative prices of operating and capital inputs
  - opex and capex substitution possibilities
  - the extent to which expenditure forecasts are referrable to a provider that is not at arm's length
- add a number of factors to the list:
  - a reasonable expectation of the demand forecast and cost inputs;
  - whether the opex or capex forecast contains amounts for projects that should be contingent projects
  - other factors as the AER considers relevant.

4.3.2 *The right balance between prescription and discretion*

Getting the right balance of prescription and discretion is critical. An imbalance could have significant adverse implications for the regime that has been set up to so carefully balance the AER's discretions against the DNSPs' need for investment certainty.

A situation in which the AER has relatively unguided discretion may lead to the increased risk of regulatory error and result in an underinvestment in energy networks. When evaluating the correct balance between prescription and discretion, the AEMC must be mindful of balancing short-term "gains" against long-term outcomes. While the AER might use increased discretion as a vehicle to lower forecasts and therefore prices in the short-term, if the effect is to reduce expenditure below efficient levels there would be an unfavourable long-term effect resulting from underinvestment which would result in lower service quality and/or higher prices in the long-term.

The right balance can be struck when the DNSPs have an incentive to use their considerable expertise to submit reasonable forecasts, the AER has the capacity and information to critically analyse those forecasts, and the AER has some level of guided discretion as to how it approves them. These are the essential elements of the *propose-respond* decision model inherent in the current NER.

The existence of these elements has given DNSPs a high level of confidence that the AER decision on their opex and capex forecasts will meet the revenue and pricing principles[28] in the NEL and, therefore, have a firmer basis for future investment.

4.3.3 Do the proposed rules achieve the right balance?

No. The AER's proposed rule diminishes the importance of the DNSP's own forecasts and removes the guidance that is necessary for DNSPs to have confidence that the AER will determine a forecast allowance that meets the revenue and pricing principles in the NEL.

Without the requirement for the AER to have due regard to each DNSP's own forecasts and with a wide discretion to determine its own forecast independently, the DNSPs would also have more difficulty contesting the AER's determination in a merits review, which would be only focussed on determining whether the AER acted reasonably in exercising its broad discretion under the rules.

In contrast, Jemena considers the current regulatory framework in the NER contains the right balance between prescription and discretion.

Our examination of the rules and Jemena's own experience indicates that the AER's power under the NER to reject and/or substitute opex and capex forecasts is not unduly restricted. Jemena believes the AER already has sufficient discretion to disallow expenditure that it is not satisfied is prudent and efficient and routinely uses this discretion.

4.4 AER's use of its discretion

4.4.1 Do the AER's proposed rules give the AER greater discretion?

Yes. The changes put forward by the AER represent a departure from the current *propose-respond* model to a *consider-determine* model.

This is a fundamental shift that is not only inconsistent with MCE policy development leading up to implementation of the national energy market but would also lead to investment uncertainty and instability of the national energy regime.

[28] NEL, 7A.

The AER claims that these changes would allow it to weigh up all available information, evidence and data in order to reach a more “balanced decision” on forecast expenditure.[29] It is not immediately clear what the AER means when it refers to “a more balanced decision”, however one potential effect of the AER’s proposal is that it would be at large to determine a wider range of outcomes, unconstrained by proper analysis of a DNSP’s proposal, and, as such, less exposed to merits review of its decision. Without some level of guidance on its discretion, it will be difficult for DNSPs to have confidence that the AER’s outcome would meet the revenue and pricing principles in the NEL.

4.4.2 Could the AER achieve the same outcomes through greater use of the discretions it already has?

If the outcome the AER is seeking to achieve is approval of opex and capex forecasts that stakeholders can have a high level of confidence meet the revenue and pricing principles in the NEL, the answer is yes.

There is strong evidence that the rules already give the AER sufficient discretion to disallow expenditure that it has determined is not prudent or efficient.

The examples provided in section 4.2.3 above on the different ways the AER has exercised this discretion to amend DNSP opex and capex forecasts, and the pricing outcomes set out in section 3.4, are testament to this.

4.5 Costs and benefits

4.5.1 Costs and benefits of making the rule changes the AER has proposed

While Jemena cannot identify any benefits associated with the AER proposed rule changes for opex and capex forecasting, it can see associated costs to the community.

These costs arise from the increased risk of regulatory error. Removing the existing guideposts to the AER’s discretion would greatly increase the risk that this discretion would miscarry, resulting in expenditure forecasts that do not reflect efficient costs.

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[29] AER, Promoting efficient investment – protecting consumers from paying more than necessary - Executive Briefing, 29 September 2011, <http://www.aemc.gov.au/Media/docs/AER%20Executive%20Briefing-a44b14bc-a016-4b5e-bb0b-f5a9d6996082-0.PDF>

This could have a catastrophic impact on electricity networks as an under allowance will at the simplest level result in under-investment in infrastructure, a high cost of capital, a decline in the quality and reliability of supply and long-term investment uncertainty in the energy industry.

4.5.2 Meeting the NEO and the NGO

Jemena does not believe the proposed rule change promotes the achievement of the NEO which requires the promotion of efficient investment. It cannot be in the long-term interests of electricity consumers to expose them to the increased likelihood of underinvestment in electricity networks.

This would in the long-term lead to poor outcomes with respect to the other components of the NEO—price, quality, safety, reliability and security of supply of electricity.

4.6 The solution

4.6.1 Are there more appropriate solutions to the problems that exist?

Jemena does not believe the AER has established there is a material problem with the current opex and capex forecasting rules.

Consequently, it would be more appropriate to:

- make no change to the current opex and capex forecasting framework
- to the extent necessary, increase the capacity of the AER to better determine and analyse the information it needs to test DNSPs' capex and opex forecasts in their regulatory proposals against the objectives, criteria and factors set out in the current rules.

5 Incentive arrangements in electricity

Key points:

- A capex incentive scheme should be designed to encourage the efficient level of capex for each business, which could be above or below the forecast the AER determines at the start of a regulatory period. This is consistent with the revenue and pricing principles.
- While all efforts can be made to accurately forecast capex, many extrinsic factors influence the efficient level over the period: actual growth in consumers, demand, better knowledge of costs, reassessments of risk, new technologies and alternatives.
- With a well-functioning capex incentive scheme, stakeholders can be more confident that businesses will spend at the efficient level.
- The AER already has discretion to develop and apply a capex incentive scheme that addresses the issues that exist in the current scheme.
- In contrast, the AER's proposed capex incentive scheme could be a major impediment to efficient investment and has undesirable implications when considered in conjunction with the AER's proposal to widen its discretion to determine capex forecasts.
- The AER's proposals on other (as-yet undefined) incentive schemes amounts to giving the AER quasi rule-making power blurring the demarcation between the AEMC as rule-maker and the AER as enforcer. This is undesirable.

5.1 The current rules

The NER currently provide that all a DNSP's actual capex during a regulatory period must be rolled into its regulatory asset base (**RAB**) at the start of the next period.

> The previous value of the regulatory asset base must be increased by the amount of all capital expenditure incurred during the previous control period.[30]

[30] NER, S6.2.1(e)(1).

The AER has discretion to determine the form of depreciation that is applied when rolling forward the DNSP's RAB.

> A distribution determination is predicated on the following decisions by the AER (**constituent decisions**): …
>
> (18) a decision on whether depreciation for establishing the regulatory asset base as at the commencement of the following regulatory control period is to be based on actual or forecast capital expenditure[31]

The AER has discretion to develop a capex incentive scheme.

> An efficiency benefit sharing scheme may (but is not required to) be developed to cover efficiency gains and losses related to capital expenditure or distribution losses.[32]

5.2 The problem

5.2.1 AER's view of the problem

Inappropriate capex incentives

The AER is concerned that the price path structure set down in the NER produces an inherent incentive to over-spend capex, particularly in the later years of a regulatory period. That incentive is stronger where the regulatory WACC is expected to be greater than the DNSP's actual cost of capital for the life of the asset, and any capex over-spend is rolled into the RAB.

The AER submits that "[t]he current rules may not provide sufficiently strong incentives to ensure that only efficient investment occurs." and cites capital expenditure in excess of forecast in NSW and Qld during the past regulatory period as a significant contributor to price increases allowed for the current regulatory period in those States[33].

The AER relies on Figure 6.2 in its proposal (replicated here as Figure 8) to illustrate its position, focusing on the circumstances where there might be an incentive to over-spend capex.[34]

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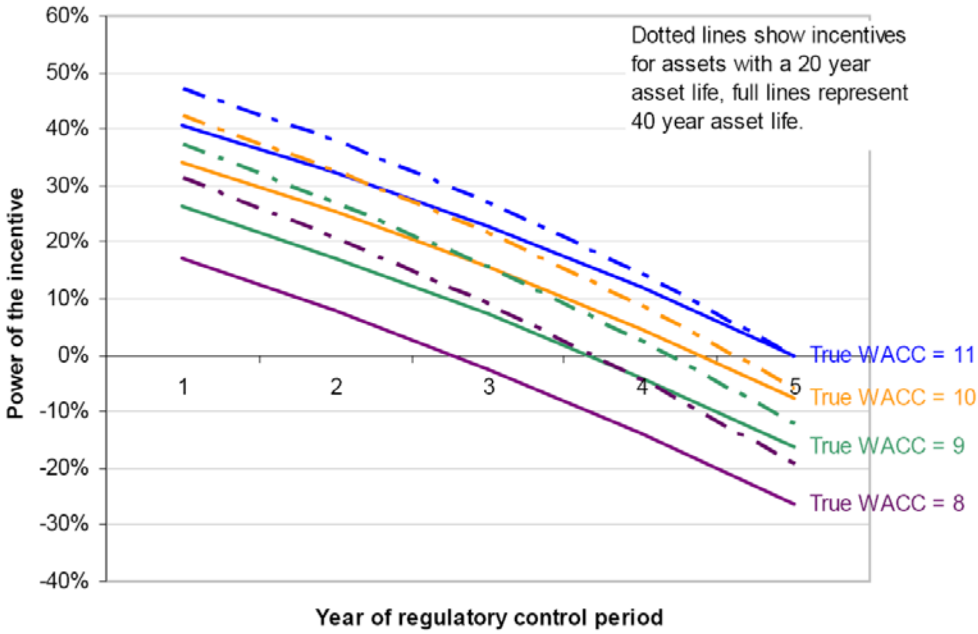
[31] NER, 6.12.1(18)

[32] NER, 6.5.8(b)

[33] AER, *Economic regulation of transmission and distribution network service providers - AER's proposed changes to the National Electricity Rules*, Part B, September 2011, p. 38.

[34] AER Part B (September 2011), p. 39.

Figure 8: AER's Figure 6.2 - Strength of incentives under different WACC outcomes



Treatment of related party margins and capitalised overheads

The AER refers specifically to related party margins and capitalised overheads as examples of costs which the AER might otherwise disallow as inefficient to be rolled into DNSPs' RABs.

The AER believes that the requirement that all a DNSP's actual capex must be rolled into its RAB may result in the amounts of capitalised overheads and related party margins that are rolled into the RAB exceeding the amounts that would be consistent with the basis used in setting the revenue requirement before the event.

Other incentive schemes

The AER submits that, under the current rules, a new incentive scheme can only be introduced through a full rule change process. Noting that regulatory best practice is continually evolving, including the development of innovative incentive schemes, the AER considers that a full rule change process is an overly costly process to incrementally develop the regulatory regime in order to keep pace with international best practice.[35]

[35] AER Part B (September 2011), p. 56.

5.2.2 Jemena's view of the problem

Capex over-spend not inherently inefficient

In Jemena's view, the AER is wrong to characterise expenditure in excess of the regulatory allowance as inherently inefficient. The allowance is a forecast made at a point of time and can be over-spent or under-spent for any number of reasons. Over-spending cannot be considered a problem if it is prudent and efficient and, so long as that is the case, any over-spend must be rolled into the RAB in full in order to satisfy the revenue and pricing principles which state that:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs …[36]

No incentive to over-spend capex allowances in aggregate

While the current arrangements may create an incentive to defer capex within a regulatory period, there is no incentive to over-spend in aggregate.

In its analysis of Figure 6.2, the AER overlooks other features of the current capex incentives for DNSPs, most notably that:

- in most circumstances, the penalty for over-spending (or incentive to under-spend) in the early years of the regulatory period is significantly greater than any incentive to over spend in the later years
- when the expected difference between the regulatory WACC and actual cost of capital over the life of the asset is small (or zero), there is an incentive to under-spend in every year.

That is, the current arrangements provide an incentive to defer expenditure to later in the regulatory period but not necessarily to over-spend in aggregate. Arguably this distorting incentive should be the focus of attention.

There are other aspects of current arrangements that the AER has not considered adequately in formulating its proposals:

- businesses are subject to practical and financial constraints on capex which are at least as significant as the incentive properties of the regulatory regime in determining actual capex

[36] NEL, 7A(2).

- by exercising its discretion to require that the next RAB roll-forward calculation be based on actual rather than forecast capital expenditure, the AER has already increased the incentive for the Victorian DNSPs to under-spend capex, particularly in the early years of the regulatory period.

When all these factors are taken into account, the balance of incentives under current arrangements is more likely to encourage under-spending in aggregate than over-spending in aggregate.

We expand on these points and related matters arising from the AER's proposals in the following sub-sections under the headings:

- Businesses face practical and financial constraints on capex
- Interpreting Figure 6.2 in the AER's proposal
- Using actual depreciation instead of forecast depreciation in the RAB roll-forward calculation increases the incentive to under-spend capex.

Businesses face practical and financial constraints on capex

Businesses are subject to practical and financial constraints on capex which are at least as significant as the incentive properties of the regulatory regime in determining actual capex.

Firstly, a business's regulatory proposal is an integrated whole and the capex forecast is only one part of that whole: capex cannot be varied independently. The capex forecast is determined by many factors including:

- forecast demand and service quality requirements
- engineering and risk considerations which take into account the current state and age of existing assets
- the outlook for labour and materials costs, some of which are dependent on exchange rates
- licence and other statutory requirements
- the business's ability to attract capital, the regulatory WACC, and financial metrics

- the business's capex planning and approval processes which mean that capex forecasts (including scope, technology, costs and timing) are constantly evolving and are necessarily better-formed and more accurate for the earlier years of a regulatory period than for the later years.

If any of those factors change at the draft decision stage of the regulatory review process then the business will review and adjust its forecast in responding to the draft decision. It is also inevitable that those factors will change with the final decision and during the subsequent regulatory period as it unfolds. The business will take those changes into account in its routine capex budgeting and approval processes which ultimately determine the business's expenditure. The incentive properties of the regime are a relevant but not a primary consideration in those processes.

Secondly, the AER focuses on the observation that there is an apparent incentive for DNSPs to over-spend in the later years of the regulatory period. While that is the case in theory—but only if the regulatory WACC is significantly greater than the business's actual cost of capital—a business has only limited scope to act on that incentive:

- A significant proportion of capex (approximately 50 per cent over the long term) is required to meet demand and make new connections as and when they occur. If, all else equal, growth in demand exceeds expectations or if the capital works required to meet expected demand are more costly than anticipated at the time of the review, then capex will necessarily exceed forecast. A business should not be penalised in those circumstances.

- Resourcing constraints mean that there is limited scope to back-load a discretionary capex program.

Thirdly, the AER overlooks other significant constraints that drive businesses, and privately owned businesses in particular, to under-spend rather than over-spend capex:

- capital is a scarce resource, particularly in today's climate

- over-spending the regulatory capex allowance will reduce free cash flow and hence interest cover which will, in turn, potentially affect the business's credit rating exposing it to a higher cost of debt.

Interpreting Figure 6.2 in the AER's proposal

The AER relies on Figure 6.2 in its proposal to support its contention that current arrangements produce and incentive to over-spend capex.

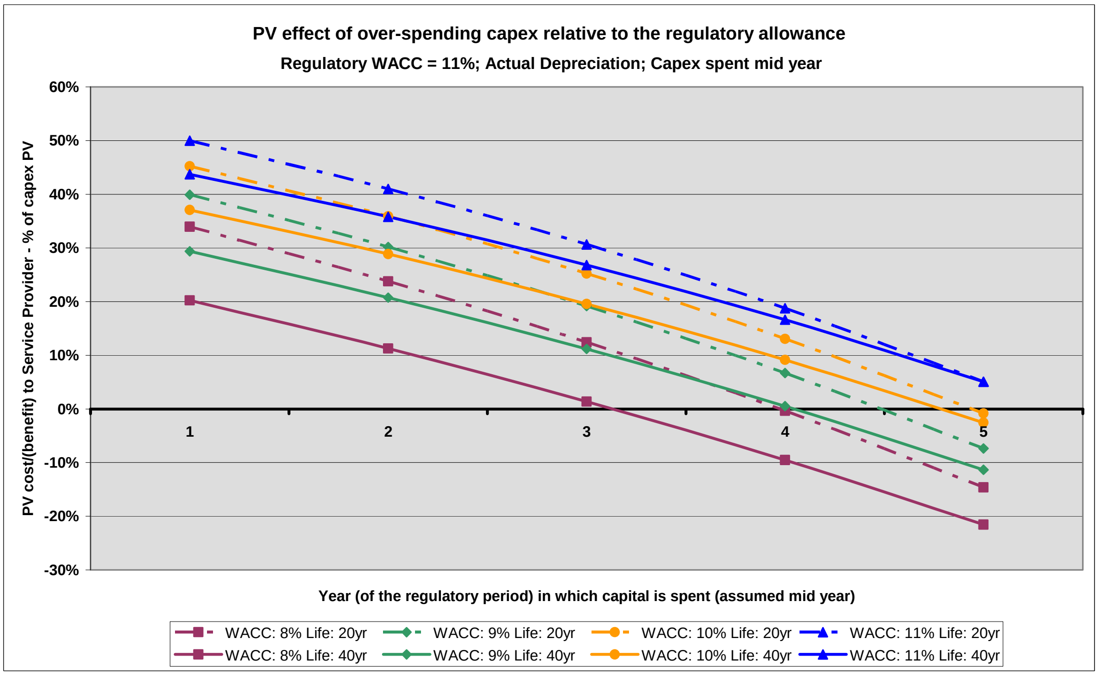
Firstly, the AER's analysis focuses on cases where the regulatory WACC exceeds the business's actual cost of capital by as much as 3 percentage points.

Any difference between the regulated WACC and the actual cost of capital in the current period will not affect incentives for over-expenditure in that period. Incentives to over-spend will only be affected where there is an expectation of future sustained disparities between the regulated WACC and the actual cost of capital. As such, the AER's analysis assumes that the business can foresee the path regulated returns (and relativities between regulated returns and the actual cost of capital) over the life of the relevant assets.

In reality, businesses do not have such foresight and in the absence of any systematic bias in determination of regulated returns can only expect a return that is roughly equal to their actual cost of capital over the life of their investments. That is, the "True WACC = 11" lines are more representative of the way that businesses will evaluate the incentives than any of the other sets of lines in Figure 6.2.

Secondly, as presented by the AER, Figure 6.2 shows 0 per cent incentive for over/under expenditure in year 5 when the business's cost of capital is equal to the regulatory WACC (11 per cent). That result is questionable. The AER's analysis is apparently based on the assumption that all cash flows, including capex, occur at year end whereas the generally accepted regulatory assumption (which is embodied in the AER's PTRM) is that capital is spent, on average, at the middle of the year, and all other cash flows occur at year end. When the analysis is performed on that basis, the picture is somewhat different as shown in Figure 9.

Figure 9: PV effect of over-spending capex relative to the regulatory allowance – actual depreciation



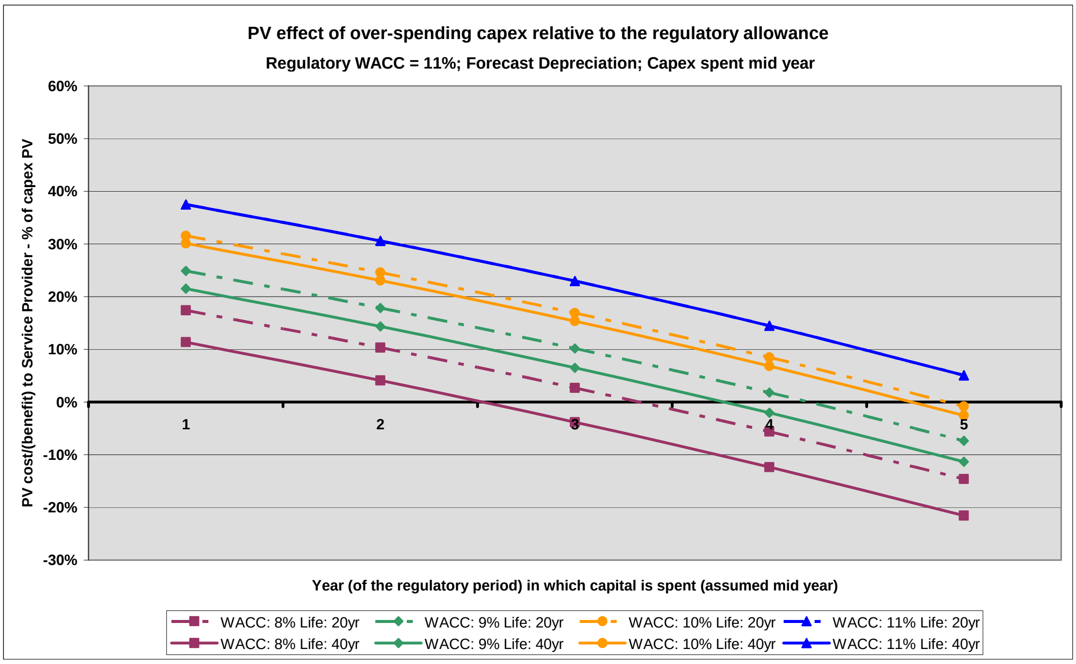
Changing the capex timing assumption results in the incentive (such as it is) to over-spend in the later years of the regulatory period being lower and the penalty for over-spending (or incentive to under-spend) in early years being greater than suggested by the AER in Figure 6.2.

While there may be an incentive to over-spend in the later years of the regulatory period if the WACC is expected to be significantly greater than the business's actual cost of capital for the life of the asset, the dominant incentives under current arrangements are to under-spend, particularly in the early years of the regulatory period, and to defer expenditure within the period. But, as noted previously, businesses have limited discretion to respond to those incentives.

Using actual depreciation instead of forecast depreciation in the RAB roll-forward calculation increases the incentive to under-spend capex

In its final decision for the Victorian DNSPs in 2010, the AER determined that actual depreciation will be used in rolling the DNSPs' RABs forward to the beginning of the next regulatory period[37]. The AER's analysis and Figure 9 above are based on using actual depreciation in the RAB roll-forward calculation. In Figure 10 we have performed the same calculation using forecast depreciation in the RAB roll-forward calculation (which is the basis that the ESC had adopted for the 2006-10 regulatory period).

Figure 10: PV effect of over-spending capex relative to the regulatory allowance – forecast depreciation



Comparing Figure 9 and Figure 10, it is clear that using actual depreciation (Figure 9) produces a stronger incentive than forecast depreciation (Figure 10) to reduce capital expenditure (or not to over-spend), especially in the early years of the regulatory period. Evidence should be gathered on how the change from forecast to actual depreciation affects behaviour before contemplating further adjustments to capex incentives of the kind proposed by the AER.

[37] AER, *Draft decision*, *Victorian electricity distribution network service providers: Distribution Determination 2011–2015,* June 2010, p. 459.

5.2.3 *Analysis of the effectiveness of the current rules over the last five years*

Figure 7 above shows the relationship between JEN's forecast and actual capex and the ESCV's capex allowance for the 2006-10 regulatory period. The data behind Figure 7 was presented as Table 8-3 in JEN's July 2010 submission[38] in response to the AER's draft decision. That table is reproduced as Table 1 below:

Table 1: 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	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

JEN over-spent its capex allowance in every year of the period except one, and by a total of $108.2 million or 28.4 per cent of the allowance. This is despite the significant incentives to defer capex within the 2006-10 period—the same capex incentives that apply to JEN under chapter 6 of the NER. At the same time JEN under-spent its own forecast in every year and by $25.8 million or 6.3 per cent in total.

In Jemena's submission, all of the capex was necessary, prudent and efficient and was properly recognised under existing rules. If the AER's proposed rules had been in place, JEN would not have spent more than its regulatory allowance, and a significant amount of efficient capex would have been foregone.

[38] Jemena Electricity Networks (Vic) Ltd, *Revised regulatory proposal*, 20 July 2010 <http://www.aer.gov.au/content/item.phtml?itemId=738448&nodeId=70607bbb67d10b8208ba20ecce53e148&fn=Jemena%20revised%20regulatory%20proposal.pdf>

5.3 Prescription and discretion

5.3.1 AER's proposed rule change

New AER capex incentive scheme in the rules

The AER proposes rule changes that will:

- only allow 60 per cent of any capex in excess of the allowed forecast for a period to be rolled into the RAB at the beginning of the next period
- provide for uncertainty by amending the rules that govern capex re-openers and extend the contingent projects arrangements to electricity distribution
- only allow related party margins and capitalised overheads to be rolled into the RAB to the extent that they have been incurred consistently with and as provided for in the capex forecast for the period.

Other incentive schemes

The AER proposes a suite of amendments relating to other incentive schemes, that is, new incentive schemes in addition to those currently provided for in the NEL. For DNSPs these are[39]:

- a new clause to provide for the AER to develop and publish an incentive scheme or schemes other than the service target performance incentive scheme and the efficiency benefit sharing scheme where the AER considers that there are benefits to end users or consumers arising from the incentive scheme or schemes
- a new clause to require a building block proposal to state how any applicable other incentive scheme or schemes are to apply
- revision to require adjustment in the building blocks of any revenue increments or decrements arising from the application of other incentive scheme or schemes developed and published under clause 6.6.5
- revision to include reference in the operating and capex factors to other incentives scheme

[39] AER, *Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules,* Part C – Draft Rules, September 2011, table 1.7, p. 7. <http://www.aemc.gov.au/Media/docs/AER%20Proposal%20on%20National%20Electricity%20Rules%20-%20Part%20C-63a3da77-f17d-4026-9283-d62740f860b0-0.PDF>

- revision to require the AER to make a constituent decision on how any applicable other incentive scheme or schemes are to apply
- a new clause to require a DNSP to provide in the building block proposal the values that it proposes are to be attributed to the parameters for the purposes of the application to the provider of any applicable incentive scheme or schemes.

5.3.2 The right balance between prescription and discretion

Capex is a significant factor in achieving both productive and dynamic efficiency. If rules are directed at improving productive efficiency in the short term and are prescriptive to the point where there can be no consideration of dynamic efficiency, as appears to be the case with the AER's proposed rule changes, then there is a significant risk that there will be adverse consequences for dynamic efficiency.

It is important to strike the right balance between prescription and discretion so that the achievement of short term productive efficiency gains is not given undue weight.

5.3.3 Do the proposed rules achieve the right balance?

New AER capex incentive scheme in the rules

The AER's proposed rules would not change the balance of prescription and discretion in the rules in relation the amount of actual capex the AER can determine is rolled into a DNSP's RAB. The AER has no discretion to determine that at present and its proposal would not change that.

The AER's proposal for a new capex incentive scheme is to change the nature of the prescription in the rules for what amount of actual capex should be rolled in.

The AER's new form of prescription is inappropriate in that it would result in the automatic disallowance of 40 per cent of defined classes of capex over-spend even where the over-spend is demonstrably prudent and efficient, unless the AER has approved it first.

For reasons set out in section 5.4, the AER's proposal for its new capex incentive scheme adds considerably to the significance of its proposal to widen its discretion to determine capex forecasts including contingent projects.

Treatment of related party margins and capitalised overheads

Similarly, the proposed rule would allow amounts of related party margins and capitalised overheads but only up to a maximum of the *a priori* allowance. This proposal is flawed in that:

- the incentives it creates operate asymmetrically—If actual related party margins and capitalised overheads are allowed up to a maximum of the *a priori* allowance, it follows that there is no incentive for the NSP to reduce those amounts
- it creates a high-powered incentive to reduce capex —That is very different from the current design of the NER which employs low- or medium-powered incentives
- it fails to recognise that businesses are constantly reviewing their structures and contracting arrangements and that those reviews can result in changes that are to the long term benefit of consumers.

Businesses are constantly reviewing and, where warranted, changing their structures and contracting relationships and those changes will invariably involve changes to the margins paid for contracted services and to the pool of overheads and the way that pool is allocated. The AER's proposal, if implemented, raises a potential barrier to such changes, even where they may be in the long term interests of consumers.

For example, in the most recent Victorian EDPR, the AER had to consider whether the related party margin that JEN had paid during the 2006-10 period should be rolled into JEN's RAB when, in the AER's view, the ESC had excluded such amounts from JEN's capex allowance in the cost build-up for that period. Based on detailed information provided by JEN, the AER accepted that it was appropriate to allow some level of related party margin to be rolled in. If the AER's proposed rule had been in place, and its view of the ESC's decision was relevant and correct, then JEN would have been denied recovery of legitimate prudent and efficient costs.

The AER's proposals for capex re-openers and contingent projects will not be effective

The AER recognises that there is a risk that its proposed rule may result in the disallowance of capex that is required to respond to unforeseen circumstances. To deal with this the AER proposes additional changes that would modify the capex re-opener provisions and extend the contingent projects arrangements to electricity distribution. These changes are intended to permit adjustment of the capex allowance to accommodate unforeseen circumstances.

The mechanisms proposed by the AER will not deal adequately with program capex that DNSPs undertake such as that driven by demand and/or connection numbers. For many projects and programs it is not possible or practical to designate in advance what is in the original forecast and what might be contingent.

The burden of proof for any variation of the capex allowance will rest with the DNSP. It is easy to imagine that there would be significant difficulties in making a successful case for an increased allowance for reinforcement or connection capex to meet an anticipated increase in demand or connection numbers.

The contingent project mechanism will not provide businesses with the certainty they need before the event as to how capex will be treated.

The incentives introduced by the AER's proposed rule changes are inconsistent with the current design of the NEL

There are a number ways in which capex (and depreciation) might be treated in the RAB roll-forward calculation. Each has different incentive properties ranging from low-powered to high-powered. Dr Darryl Biggar describes three of the available alternatives as follows[40]:

(a) Roll forward based on actual capex and forecast depreciation (which, as we will see, leads to low-powered incentives to reduce capital expenditure)

(b) Roll forward based on actual capex and actual depreciation (which leads to medium-powered incentives to reduce capital expenditure)

(c) Roll forward based on forecast capex and forecast depreciation (which leads to high-powered incentives to reduce capital expenditure).

The NEL provides for the low- or medium-powered alternatives described in (a) and (b), where the choice between using forecast or actual depreciation is at the discretion of the AER[41]. Incentive mechanisms that involve rolling in forecast capex as opposed to actual capex provide high-powered incentives to reduce capital expenditure. Dr Biggar goes on to say that:

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[40] Biggar, D., *Updating the Regulatory Asset Base: Roll-Forward, Re-Valuation and Incentive Regulation,* April 2004, p. 3. <http://www.aer.gov.au/content/item.phtml?itemId=660004&nodeId=4a548dc164e112435950f30d7b359593&fn=Asset%20Base%20Roll%20Forward%20Principles%20-%20Dr%20Darryl%20Biggar.doc>

[41] NER, 6.12.1(18).

> It should be emphasised that such high-powered incentives to reduce capital expenditure [i.e. the option described in (c) above] are not always desirable. Incentives to reduce expenditure must be balanced with the incentive to promote service quality. … If the incentives to reduce expenditure are strong while the incentives for promoting service quality are weak or moderate, there is a serious risk of long-term under-investment with the risk of deteriorating service quality[42].

The AER's proposals to disallow automatically 40 per cent of capex in excess of the regulatory allowance and to restrict rolling in some components of capex to forecast levels establish undesirable high-powered incentives to reduce or limit capex. The proposals are therefore inconsistent with the current scheme of the NEL which has adopted low- to medium-powered incentives for capex.

Other incentive schemes

The AER's proposal that it should have discretion to develop other incentive schemes does not create the right balance between discretion and prescription.

Jemena disagrees with the AER's proposal that it should have discretion to develop "other" incentive schemes. The AER proposal does not identify the nature of these schemes.

The AER's proposal has the effect of conferring a quasi rule-making power on the AER in relation to incentive schemes. The matters in relation to which incentives schemes could be developed were originally specified by AEMC (in respect of chapter 6A) or by officials acting for the Ministerial Council on Energy (in respect of chapter 6). The AER's only reason for seeking the additional power is that the rule change process is overly costly.

The distinction between rule-making by the AEMC and enforcement by the AER is a valuable feature of Australian regulatory design.

5.4 AER's use of its discretion

5.4.1 Do the AER's proposed rules give the AER greater discretion?

New AER capex incentive scheme in the rules

Yes. When taken together with the AER's proposal to widen its discretion to determine capex forecasts, the AER's proposed capex incentive scheme would significantly increase the AER's discretion to dictate the level of capex.

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[42] Biggar, D., *Updating the Regulatory Asset Base: Roll-Forward, Re-Valuation and Incentive Regulation,* April 2004, p. 3.

Effectively, by proposing its new capex incentive scheme, the AER is seeking to introduce an ex-ante capex approval process such that only forecast capex it approves (either at a price review or as a contingent project) may be fully rolled into each DNSP's RAB.

Should the AER's scheme come into effect, DNSPs are likely to aim to spend less than the approved forecast to guard against the possibility that unexpected external factors —e.g. customer connections, demand, and their impacts on reliability— will force them to over-spend their capex, and a substantial proportion of any over-spend will become unrecoverable.

The AER's capex incentive scheme is arguably not one aimed at promoting efficient investment—that is the level of investment necessary to meet the changing needs of the market.

Treatment of related party margins and capitalised overheads

The combined effect of the AER's proposal for the treatment of related party margins and capitalised overheads and its proposal to widen its discretion to determine capex forecasts, is that the AER would have considerably greater discretion to influence the level of related party margins and capitalised overheads but only on an ex-ante basis. Again, the AER's proposal is not designed to promote efficient investment when circumstances change during the regulatory period.

Other incentive schemes

Yes. The AER's proposed rule changes would also provide for the AER to develop and publish one or more new incentive schemes. This amounts to giving the AER very wide discretion effectively conferring on it a quasi rule-making power. This blurs the relationship between the AEMC as rule-maker and the AER as enforcer.

5.4.2 Could the AER achieve the same outcomes through greater use of the discretions it already has?

Improved capex incentive scheme

If a desired outcome is to establish an improved capex incentive scheme that addresses the minor timing issues that currently exist, then yes, the AER could achieve the same outcome through greater use of the discretions it already has under NER section 6.5.8(b).

Treatment of related party margins and capitalised overheads

If a desired outcome is to ensure that only efficient related party margins and capitalised overheads are rolled into each DNSPs, then no, the AER could not achieve the same outcome through greater use of the discretions it already has. As discussed in section 5.6 there is a more appropriate solution.

Other incentive schemes

No, the AER does not currently have discretion to develop and apply incentive schemes beyond those listed in the rules. Jemena believes this is appropriate.

5.5 Costs and benefits

5.5.1 Costs and benefits of making the rule changes the AER has proposed

New AER capex incentive scheme in the rules

We have observed previously that the AER's proposed changes to capex incentives, when taken together with other proposed changes that would increase the AER's discretion in setting the capex allowance, would effectively give the AER unfettered discretion to determine what is capex in excess of allowance and could lead to the disallowance of capex that is demonstrably prudent and efficient. The AER's proposed rule change to allow related party margins and capitalised overhead but only up to a maximum of the *a priori* allowance is similarly flawed.

Both changes create a high-powered incentive to reduce capex and are therefore inconsistent with the current design of the NEL which employs low- or medium-powered incentives.

When taken together with other aspects of the AER's proposed rule changes that are aimed at giving the AER greater discretion in the way that it sets capex allowances[43]—and which the AER implies openly it will use to reduce allowances—the adverse consequences of penalising expenditure in excess of the allowance will be exacerbated. There is an increased likelihood that the capex allowance and hence prices will be set too low at the same time as new penalties are imposed for spending in excess of the allowance. To the extent that businesses over-spend the allowance, they will be penalised both within the regulatory period because allowed revenue is lower than it should be; and in subsequent regulatory periods because they are denied a return on and of a significant proportion of any capex

[43] See for example AER Part A (September 2011), pp 12 and 14; and Part B (September 2011), p. 26, as well as Reeves (2011).

over-spend, even when that over-spend is demonstrably prudent and efficient. Investors will face increased risk and uncertainty as a consequence.

The AER's proposed rule changes, if implemented, would act as a significant, and potentially damaging, additional deterrent to expenditure in excess of the regulatory allowance. It is likely that necessary capital works will either be deferred or cancelled. Alternatively, for consumer-initiated capex, businesses will seek increased customer contributions.

Such outcomes cannot be consistent with the NEO and the revenue and pricing principles. In Jemena's view there are no benefits associated with the proposed changes.

5.6 The solution

5.6.1 Are there more appropriate solutions to the problems that exist?

Improved capex incentive scheme

The AER already has the discretion to develop an efficiency benefits sharing scheme for capex and Jemena supports the AER's use of that discretion.

The ENA has included with its submission an expert report entitled "Design of Capital Expenditure Incentive Arrangements". As well as providing a thorough analysis of the incentive properties of current arrangements and an assessment of the AER's proposal in that context, the report proposes criteria for the design of a capex incentive scheme and enhancements to the existing framework in section 6.5.8 of the NER. Among other things, the proposals in this report seek to address the incentive inherent in current arrangements to defer capex within the regulatory period. Jemena supports the expert report.

Treatment of related party margins and capitalised overheads

If a desired outcome is to ensure that only efficient related party margins and capitalised overheads are rolled into each DNSP's RAB, Jemena can see scope for the AER being given increased discretion to conduct an ex-post review of over-spends on related party margins and capitalised overheads before they are rolled in.

Other incentive schemes

Chapter 6 of the NER already provides for a range of incentive schemes. In some cases the ability to develop and implement schemes under the NER provisions is discretionary and the AER has not fully exercised the discretion it has.

Jemena considers that any new incentive scheme should be developed through the existing rule change process, consistent with the current design of the electricity regime. However, if the AER is to be given the discretion to introduce new incentives schemes itself then that discretion must be appropriately circumscribed.

6 The cost of capital for both electricity and gas

Key points:

- We encourage the AEMC to apply a very high threshold before adopting any changes to a key parameter like the cost of capital—that threshold being whether a major problem with the current rules has been clearly established.
- The cost of capital determined in recent AER determinations reflected the prevailing market conditions for funds during and just after the GFC.
- Part 9 of the NGR (for gas) and chapter 6 of the NER (for electricity distribution) contain sufficient flexibility to cope with a major shock like the GFC and have worked well. Chapter 6A of the NER (for electricity transmission) performed less well.
- The number of merits review grounds has been small, driven by the framework not allowing for merits review of the AER's 2009 Statement of Regulatory Intent (**SORI**), and has been effective in correcting AER errors.
- There may be a case for incremental changes:
  - adjusting, but not removing, the prescription in chapter 6 in relation to DRP
  - aligning chapter 6A with chapter 6.
- However, there is no case to make any other major change.

6.1 The current gas and electricity rules

The rule change proposals from the AER and the EURCC suggest changes to a number of aspects of the existing rules, as they apply to the cost of capital.

6.1.1 Wide discretion in gas rules

The NGR provide the AER with a wide discretion to accept a cost of capital that is commensurate with prevailing conditions in the market for funds and the risks involved in providing the regulated services. In calculating that cost of capital, the

NGR require the AER to assume that the firm meets benchmark levels of efficiency in its operations and funding.

The NGR also require the use a well accepted approach that incorporates the cost of equity and debt, and a well accepted financial model, such as the Capital Asset Pricing Model (**CAPM**).[44]

6.1.2 Pre-set or stable parameters in electricity rules

For electricity transmission, chapter 6A of the NER requires that the AER sets parameters or methods in a five yearly review of the cost of capital and use them when determining the cost of capital to be used in a transmission determination.[45]

For electricity distribution, the current rules require the AER to use the parameter or methods it sets in a five yearly review, unless there is persuasive evidence justifying a departure in that particular case.[46]

The persuasive evidence test also applies during the five yearly review in both electricity distribution and transmission when the AER considers whether or not to change a pre-existing value or method for a parameter.

6.1.3 The concept of a benchmark efficient firm for the cost of debt

As noted above, the NGR use the concept of a benchmark efficient firm when considering the appropriate cost of capital.[47] Similarly, the current electricity rules seek to estimate the cost of debt for a benchmark efficient firm and to provide for the recovery of that cost of debt through the revenues of regulated businesses.[48]

The current rules, both electricity and gas, do not take into account and do not seek to mimic the actual cost of debt of any individual or any group of regulated businesses.

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[44] NGR, 87.

[45] NER, 6A.6.2.

[46] NER, 6.5.4(e) and 6.5.4(g).

[47] NGR, 87.

[48] NER, 6.5.2(e).

6.1.4 *Detailed prescription on debt risk premium and risk free rate in electricity*

The current electricity rules provide detailed requirements for the AER to follow when calculating the risk free rate parameter of the cost of capital. The rules also set out some detailed requirements for estimating the debt risk premium.

6.2 The problem

6.2.1 *AER's view of the problem*

Need for administrative ease

The AER's view is that there appears to be little justification for having different arrangements in setting the cost of capital between electricity distribution businesses, electricity transmission businesses and gas businesses. The AER considers that the cost of capital is a benchmark and is largely independent of business/industry considerations.

Too many merits reviews

The AER claims that a number of problems have arisen under the current rules:

- The current distribution rules provide for the AER and distributors to be in continual 'WACC review' mode where considerable resources are spent at every determination process re-examining issues.
- The incentive for distributors to argue with the AER has also resulted in reviews by the Tribunal in pursuing a level of precision which can only be considered spurious in the context of many WACC parameters.
- Where the AER has undertaken a thorough review in the context of chapter 6A and made an overall decision which reflects the views and interests of all stakeholders, it remains open for DNSPs to cherry pick those component parameters of the WACC which they consider unfavourable for them.

This process detracts from the AER's ability to adequately consider the resulting overall rate of return.

Difficulties in setting cost of debt

The AER also believes that the current rules provisions have given rise to difficulties in setting allowances for the cost of debt.

The AER believes that the restrictive nature of the debt risk premium (**DRP**) definition in the rules has resulted in significant debate and merits review processes that have focussed on technical arguments around an appropriate choice of data to satisfy the benchmark definition rather than how best to achieve outcomes that are in the long term interests of consumers.

The AER believes that there is a growing disparity between the DRP that the AER must determine under the rules and the actual cost of debt for businesses.

6.2.2 EURCC's view of the problem

Regulatory cost of debt is higher than actual cost of debt

The EURCC believes that:

- the cost of debt resulting from the current rules is too high and is above the actual cost of debt experienced by the regulated businesses
- the cost of debt parameter in the cost of capital calculation should more closely reflect the actual cost of debt experienced by the regulated businesses, and that this should include an explicit adjustment for the fact that government-owned businesses have a lower cost of debt than privately owned ones
- the cost of capital should be set on an annual basis to more closely align with a business's actual cost of debt.

6.2.3 Jemena's view of the problem

Prevailing conditions in the market for funds is driving cost of capital

Recent increases in the cost of capital determinations reflect the reality of a more volatile financial world following the global financial crisis (**GFC**) and the fact that obtaining funding now is more expensive than it previously has been. The detail of the AER and the Tribunal decisions bears this out.

The increases in the cost of capital parameters have mainly been driven by increases in two key factors—the market risk premium (**MRP**) and the DRP. Both of these increases are justified at this point in time, given the current market conditions and the outlook for the foreseeable future.

Current rules have performed well under difficult market conditions

Over the past few years, part 9 of the NGR and chapter 6 of the NER have contained sufficient flexibility to cope with a major shock like the GFC.

These rules are also flexible enough to allow the AER to reduce these parameters if the market conditions change and benchmark efficient funding costs reduce.

The NGR and chapter 6 of NER have been flexible enough to deal with the fallout from the GFC as it unfolded and with AER errors in the SORI.

Clear limitations emerged in chapter 6A. In Jemena's view the chapter 6A framework has been the worst-performed of the three frameworks currently in place. The chapter 6A framework does not allow for the flexibility that is required to respond to changing market conditions (such as the ability to depart from the SORI) or AER errors in the SORI. The combination of the two features ensures that any material errors made by the AER in setting the cost of capital through the SORI are maintained for a long period of time.

Merits reviews have corrected AER's errors

Only three aspects of the AER's decisions on WACC have been taken to merits review – the averaging period, DRP and gamma. The number of individual reviews has been driven by the framework not allowing for merits review of the AER's 2009 SORI.

As a result, in each case where the AER erred on, for example, the value of gamma, the affected business had to wait until its individual determination process was completed to initiate a merits review of that issue. DNSPs pursuing merits reviews on gamma presented similar evidence to the Tribunal, allowing for expeditious hearing of this issue in later processes.

The Tribunal has also been highly consistent in its treatment of the issues and has, through its iterative decisions, corrected the AER's errors and created a valuable body of precedent, which establishes a clear interpretation of the current rules.

Difficulties in setting cost of debt

The AER has had the difficult task of establishing, through the SORI process, a method for determining the DRP and then applying that method in subsequent price reviews, all in a manner that is consistent with the requirements of the NER.

In the light of experience to date, Jemena accepts that minor incremental improvements may be desirable. However, there is no case for fundamental changes or the removal altogether of the rules guidance on DRP.

Need for administrative ease

Efficiency in setting the cost of capital for electricity distribution businesses, electricity transmission businesses and gas businesses can be achieved, and is being achieved, with the current rules.

The AER already runs its review of the cost of capital for electricity transmission and distribution businesses concurrently. To a large extent gas network businesses and the AER have already chosen to apply the methods and even some of the parameters from the 2009 SORI to access arrangements.

However, one cannot assume that the cost of capital determined in a single five-yearly review will be an appropriate benchmark for all gas and electricity businesses. A single five-yearly review cannot take account of the significant differences that exist between the businesses, their markets, their services and the market conditions that might prevail at the time.

Administrative ease is an inadequate justification for changing the method for determining such a critical regulatory element as the cost of capital. A drive to standardise approaches and rationalise effort needs to be tempered with a commitment to preserve the integrity of the principles that underpin the cost of capital itself.

Need for regulatory stability

We encourage the AEMC to apply a very high threshold before adopting any changes to a key parameter like the cost of capital—that threshold being whether a major problem with the current rules has been clearly established.

While there may well be a case for minor incremental changes to the cost of capital framework in relation to DRP, and some change to chapter 6A, no robust case has been provided for more major change to chapter 6 of the NER or part 9 of the NGR, which have both only been in place for a few years.

A stable and appropriate approach to setting the allowable return on investment is a key pillar of any robust regulatory regime. From an investor’s perspective it is important that the allowed return is:

- set at a level adequate to cover the cost of capital used to fund the investment, and

- stable and predictable over the life of the investment.

Of all parameters in the regulatory framework, the cost of capital parameter arguably has the strongest influence on the dynamic efficiency of the market for electricity distribution services. A lower than appropriate value for the cost of capital, or significant uncertainty around what the value will be over time, can both result in deferred investment.

As we observe in section 6.6.1, Standard & Poor's immediate reaction to the AER's proposals is that the mere possibility of change has directionally increased the cost of borrowing for privately owned regulated businesses. This reflects the additional risk and uncertainty created through introducing the potential for change so quickly and destabilising what, to date, had been considered a stable and predictable regulatory framework.

6.2.4 Analysis of the effectiveness of the current rules over the last five years

First 5-yearly cost of capital review for electricity – the 2009 SORI The first review of the cost of capital for electricity took place during the early stages of the GFC and the rules provided the AER with sufficient discretion to make some necessary adjustments to recognise the changing market conditions in its 2009 SORI. The AER raised the MRP and at the same time it reduced the equity beta.

In its 2009 SORI, the AER also set out an approach to the DRP that, when applied in combination with the discretion provided at the time of making a determination and with the added discipline of merits appeal, proved to be adequate to address changing market conditions.

The evolution of a cost of capital approach for electricity distribution and gas networks

Jemena has had the benefit of experiencing the operation of chapter 6 of the NER (applying to JEN) and Part 9 of the NGR (applying to JGN). Jemena is therefore in a good position to compare and contrast the performance of these two frameworks.

Overall, Jemena considers that both of these frameworks have performed well. The two frameworks have shown a sound capacity to handle changing market conditions, as well as a capacity to properly handle and correct material errors made by the AER.

Table 2 and Table 3 below summarise the progression of WACC parameters for JEN and JGN from the AER's draft decisions to merits review.

Table 2: JEN – progression of WACC parameters

Item	Draft Decision[49]	Revised proposal[50]	Final Decision[51]	Merits Review
Nominal risk-free rate (%)	5.65	5.65	5.65	5.65
Expected inflation rate (%)	2.57	2.57	2.57	2.57
Real risk-free rate (%)	3.00	3.00	2.99	2.99
Gearing level (debt/equity)	0.60	0.60	0.60	0.60
Market risk premium (%)	6.5	8.0	6.5	6.5
Equity beta	0.8	0.8	0.8	0.8
Debt risk premium (%)	3.25	4.28	3.70	Awaiting Tribunal decision
Nominal pre-tax return on debt (%)	8.90	9.93	9.35	
Nominal post-tax return on equity (%)	10.85	10.85	10.85	
Nominal vanilla WACC (%)	9.68	10.29	9.95	
Gamma[52]	0.65	0.2	0.5	0.25

[49] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, Table 19.

[50] Ibid., Table 20.

[51] Ibid., Table 21.

[52] Ibid., pp XLI—XLII,

Table 3: JGN – progression of WACC parameters

Item	Draft Decision[53]	Revised proposal[54]	Final Decision[55]	Merits Review[56]
Nominal risk-free rate (%)	5.52	5.58	5.85	5.85
Expected inflation rate (%)	2.47	2.52	2.60	2.60
Real risk-free rate (%)	2.98	2.98	3.17	3.17
Gearing level (debt/equity)	0.60	0.60	0.60	0.60
Market risk premium (%)	6.5	6.5	6.5	6.5
Equity beta	0.8	na	0.8	0.8
Market beta	na	0.59	na	na
Growth beta	na	0.48	na	na
Size beta	na	0.3	na	na
Growth risk premium (%)	na	6.24	na	na
Size risk premium (%)	na	-1.23	na	na
Debt risk premium (%)	4.32	4.48	2.93	4.17
Nominal return on equity (%)	10.72	12.04	11.05	11.05
Nominal return on debt (%)	9.84	10.06	8.78	10.02
Nominal vanilla WACC (%)	10.19	10.86	9.69	10.43
Gamma[57]	0.65	0.2	0.65	0.25

Cost of equity for JGN

In its initial proposal, and again in its revised proposal, JGN submitted that the AER should use the domestic version of the Fama-French three factor model rather than the CAPM to calculate JGN's cost of equity. JGN provided a substantial amount of material, including expert reports, in support of its submission that the Fama-French model is a "well accepted financial model" that satisfies the

[53] AER, *Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, June 2010, Table 4.

[54] Ibid., Table 3.

[55] Ibid., Table 3.

[56] JGN AAI, Table 7-1.

[57] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, pp 8–9.

requirements of section 87 of the NGR. The AER rejected those submissions in both its draft and final decision. JGN did not seek a review of that decision.

Gamma for JGN and for JEN

The story on gamma provides a good case study on the importance of the framework providing a robust error-correction mechanism, and the value created through precedent.

In its 2009 SORI the AER had set gamma at 0.65. The AER then also noted that it may apply the approaches and parameters from the SORI to gas networks.[58] At the time of that decision, Jemena (both individually and as part of the ENA) voiced its strong views that the 0.65 figure was based on erroneous conclusions. Extensive evidence was provided to the AER to demonstrate what Jemena and the ENA believed were errors in the AER's reasoning.

Both chapter 6 of the NER and part 9 of NGR allow regulated businesses to propose cost of capital parameters that they believe are appropriate. In the case of electricity distribution, where the business departs from the SORI, it must provide persuasive evidence for this departure.

Both JGN and JEN proposed gamma values that were well below 0.65 and maintained this position throughout their respective determination processes. The AER also maintained its position. Under the relevant rules, the impasse could be resolved by recourse to the Tribunal.

In JGN's merits review proceedings—which were heavily influenced by parallel proceedings *Re Energex*[59]—the AER conceded error for part of the calculation of gamma, while the Tribunal found error with another part of the calculation. The Tribunal reduced the gamma value to 0.25. Through this process the Tribunal provided valuable guidance not only on the value of gamma that is to be used, but also how that parameter should be calculated in the future.

The process has provided more certainty to businesses for the long term.

Without the ability to depart from the SORI on the basis of persuasive evidence, the AER would have continued to apply an erroneous value for gamma, despite being presented with robust evidence demonstrating the error. Jemena therefore

[58] AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 6.

[59] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011) http://www.austlii.edu.au/au/cases/cth/ACompT/2011/9.html.

believes that the persuasive evidence test and access to merits review are key feature of this regulatory regime.

While the final determination in the JEN merits review is still pending, the Tribunal has indicated its intention to set the value of gamma at 0.25 as it has done for JGN and in *Re Energex*. Jemena considers that future determinations on gamma should be less contentious if the guidance provided by the Tribunal is followed.

Debt risk premium for JGN and for JEN

In the case of the DRP, the issues were more complex.

Unlike gamma, the SORI does not set out a value for the DRP, only certain parameters (credit rating and maturity) to be used in determining the benchmark corporate bond rate[60]. The DRP debate has been about how to determine the benchmark corporate bond rate, which the NER require.

In their regulatory proposals, both JGN and JEN applied the AER's SORI credit rating and maturity to their estimation of the DRP, even though JGN has the opportunity to propose something else.

Both proposed to use the Bloomberg fair value curve on the basis that it provided a better fit to observed yield data than the alternative CBASpectrum curve.

For JGN, the AER rejected this position and decided that the CBASpectrum curve alone should be used as the basis for the DRP.

In the case of JEN the decision was somewhat different. In the period between the JGN and JEN decisions:

- the Tribunal had decided to adopt an average of the Bloomberg and CBASpectrum values in merits review proceedings initiated by ActewAGL
- CBASpectrum had notified the AER that it had ceased publishing its fair value yield curve
- Australia Pipeline Trust (**APT**) had issued a new 10 year BBB rated bond.

[60] AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 29.

Taking these developments into account, the AER decided to use a 75:25 weighted average of the Bloomberg value and the APT bond yield as the basis for the DRP for JEN.[61]

Both JGN and JEN sought merits review of the AER's decision on the DRP. Challenges mounted by JGN, JEN and other businesses in relation to DRP have focused less on the rules and more on the AER's application of the AER's SORI parameters for DRP. JEN also sought to have two arithmetic errors corrected.

The Tribunal subsequently decided in JGN's review that the Bloomberg curve alone should be used, and the AER has conceded JEN's arithmetic errors. The Tribunal's decision in relation to JEN's other DRP grounds is still pending.

A key benefit of the Tribunal's detailed decisions so far has been the guidance and precedent provided.

Overall effectiveness of the current rules

The persuasive evidence test operated to accommodate a better understanding of the evidence of gamma.

The area that did not perform well was the ability of stakeholders to engage in the process:

- when the AER to determined the SORI
- when the AER applied the SORI, or deviated from it, for JEN's determination
- when the Tribunal considered JEN grounds for merits review of the AER decision[62].

The issues were complex, highly technical and required an advanced understanding of corporate finance. At this time, many consumer groups do not have the resources necessary to participate in debate at this level.

[61] AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, pp XXXVIII–XXXVIX.

[62] May Mauseth Johnston, *Barriers to fair network prices*, A report prepared for the Consumer Action Law Centre and the Consumer Utilities Advocacy Centre, p. 8..

6.3 Prescription and discretion

6.3.1 AER's proposed rule change

Generally, the AER is proposing to bring both part 9 of the NGR and chapter 6 of the NER rules in relation to return on capital closer to chapter 6A.

Changes to chapter 6 of the NER

The AER is proposing to:

- reduce prescription and increase discretion when the AER sets the risk free rate and DRP parameters by removing much of the guidance that is currently in chapter 6.

- make the outcomes of the five-year WACC review binding and remove from chapter 6 the option of using parameters different to those determined through the WACC review process where there is persuasive evidence justifying a departure.

- remove the requirement that, when undertaking a WACC review, before moving a way from a currently established parameter, there needs to be persuasive evidence supporting such a move.

Changes to Part 9 of the NGR

Part 9 of the NGR currently provides wide discretion to the AER to determine the cost of capital for each gas business.

The AER's proposed changes to the NGR would change that discretion and hard code a framework similar to the one that applies in chapter 6A (to electricity transmission).

6.3.2 EURCC's proposed rule change

The EURCC proposes a rule change to the cost of debt provisions in chapter 6 and 6A of the NER, with the stated intent of moving that regulatory parameter closer to the actual cost of debt for a particular firm.

In doing so, the EURCC is proposing that historic averages, rather than forward looking estimates should be used. The EURCC is also proposing that different approaches be used for government-owned and privately-owned businesses.

6.3.3 The right balance between prescription and discretion

Current balance is right

The current trade-off in between prescription and discretion—as set out in chapter 6 of the NER and part 9 of the NGR—represents the right balance for electricity and gas, respectively.

The current chapter 6 of the NER rules are designed as low discretion rules with good reason. The lower the discretion afforded in the rules—the more predictable the outcome of regulatory decisions and the more stable the regime. The trade-off for this stability is the reduction in flexibility, which means it is more difficult for the regime to deal with unpredictable scenarios. However, the GFC has been a good demonstration of the level of discretion in the rules being sufficient to deal with an unpredictable event that had a large-scale impact on the cost of capital.

In the case of the NGR, the AER has self-limited the wide discretion it has been afforded in Part 9, recognising the need for consistency and predictability with chapter 6 as its anchor.

Access to merits review

The current chapter 6 of the NER rules also sets a good model for balance of prescription, discretion and accountability for the purposes of investment certainty in that the businesses have the ability to seek merits review if the AER makes an error.

Having said that, Jemena anticipates that merits reviews will decrease in frequency now that the current rules have been interpreted.

Balance between rule making and rule administration

In considering any increase in discretion for the rule enforcer—the AER—it is also important to consider the delicate balance between policy or rule making and rule administration, especially with a key high-value parameter like the cost of capital.

Providing wide discretion to the regulator risks delegating policy and regulatory design decisions to the entity that administers the rules on a day to day basis. Such delegation is not appropriate in a regulatory regime with good governance.

6.3.4 Do the proposed rules achieve the right balance?

AER's proposed rule change

Jemena believes that the AER's proposed rules do not achieve the right balance.

The AER's proposed changes would increase discretion in some areas (risk free rate, debt risk premium, lack of a merits review), while reducing it in some other areas (lack of ability to depart from a WACC review outcome). On balance, the proposed rule changes reduce certainty by increasing discretion and reducing accountability. The area where the AER proposes to reduce discretion will make it harder for the regime to deal with unforseen events.

Making the outcomes of the five-year WACC review binding would also have the effect of removing a regulated business's access to merits review on the AER's decision as to the appropriate cost of capital parameter to apply to an individual business. This change the balance of discretion and accountability of the AER and therefore increases risk for regulated businesses.

For the reasons set out above, Jemena considers that there must be a 'safety valve' on AER WACC review decisions, as is currently provided for in chapter 6. Moving to the chapter 6A framework which lacks a safety valve increases the risk that regulatory error will go uncorrected and is likely to lead to rate of return outcomes that are unrepresentative of prevailing market conditions.

The rule changes also do not address the ability of consumer groups to more effectively engage in the regulatory process.

EURCC's proposed rule change

The EURCC's proposed rule changes would increase prescription in the rules and reduce the AER's discretion to determine a method for determining DRP.

Also, making material changes to the risk free rate and DRP parts of chapter 6 of the NER at this point in time, as suggested by the EURCC would have the effect of unravelling the sound body of knowledge and precedent created by the Tribunal through the merits review processes.

Jemena does accept that the content of some of the specific guidance on the DRP in chapter 6 of the NER may require incremental changes. These changes are suggested in the ENA submission, which Jemena supports.

6.4 Issues specific to the EURCC's proposal

6.4.1 EURCC's excessive profit analysis

Jemena considers that the EURCC's analysis of the cost of debt—as presented in its submission and by Brian Green and Bruce Mountain at the forum convened by the AEMC on 23 November—is flawed in that it compares the EURCC's estimates of the historic actual costs of debt of various firms against a forward-looking parameter set by the AER for a benchmark efficient firm. The ENA discusses this in its submission.

6.4.2 Government-owned NSPs vs privately owned NSPs

Jemena supports the original policy intent of the NER and NGR, which is to focus on a benchmark efficient firm and to preserve the principle of competitive neutrality, which is discussed in more detail below. The focus on a benchmark efficient firm recognises that each regulated business will have different strengths and weaknesses, and each will take a different path to improving its efficiency.

With prices being set on the basis of benchmark efficient costs, businesses are then left to each find their own way to live and thrive within those pricing constraints. This mechanism is at the very core of the incentive regulation framework that is currently in place.

6.4.3 Competitive neutrality and capital market discipline issues

The approach promoted by the EURCC, where prices are set to fund a different cost of debt and therefore a different cost of capital for a business depending on its ownership structure, conflicts with the long-established competitive neutrality principle. Such an approach could distort investment as consumers seek out supply of network services from government-owned businesses, whose prices will be forced lower. Those businesses would also not be able to earn a reasonable commercial return, as they are rightly required to by their government shareholder.

6.5 AER's use of its discretion

6.5.1 Do the AER's proposed rules give the AER greater discretion?

As noted above, on balance, the proposed rules give the AER greater discretion, while reducing the AER's accountability for the use of that discretion.

6.5.2 *Could the AER achieve the same outcomes through greater use of the discretions it already has?*

It is not entirely clear what outcomes the AER is seeking to achieve with its proposed rule changes, though Jemena's interpretation is that the AER's objective is to obtain additional discretion to be able to set a lower cost of capital allowance for regulated businesses than the one set to date.

The AER has a range of discretions accorded to it under Part 9 of the NGR and chapter 6 of the NER along with the sound checks and balances—such as a good level of prescription and access to merits reviews. This means that electricity distribution and gas businesses can have reasonable confidence that, even if the AER exercises it discretion differently, it will still meet the revenue and pricing principles in the NGL and NGL.

Outcomes in relation to DRP

Jemena notes that the one example provided by the AER in support of the AER's view that more discretion is needed in setting cost of capital parameters, is the AER's assertion that the values for DRP resulting from recent merits reviews of AER's DRP decision are resulting in values well above the actual cost of debt for many regulated DRPs (AER section 7.5.4).

As section 6.2.4 explains, lack of discretion in the rules does not appear to have been a primary cause of recent disputes around the DRP. The merits reviews of the AER's decisions on JGN's and JEN's DRP were focused on AER errors in the application of its own methodology to determine the benchmark corporate bond rate. The AER already has discretion to change the parameters for determining the benchmark corporate bond rate (currently set out in the SORI) and/or the methodology.

That said, Jemena acknowledges that there may be some deficiencies in the current definition of the DRP in the NER and that this definition may be unduly restrictive. Jemena adopts the ENA submission in relation to proposed solutions to these deficiencies.

Persuasive evidence test

A good example of the AER's ability to exercise discretion is the persuasive evidence test in chapter 6 of the NER, which is designed to place additional weight on previously established parameters. This test has been met on a number of occasions.

The AER applied this test and met it in order to change the averaging period that applied to JEN in order to calculate market observables, including the risk free rate and the debt risk premium. The AER also met this test in order to set a different value for gamma (the assumed value of imputation credits) in the determination for Victorian electricity distributors. The Tribunal also applied (and met) this test when setting a value for gamma for *Re Energex* in electricity and JGN in gas.

Jemena therefore considers that the AER already has sufficient discretion on setting the cost of capital parameters, including the debt risk premium and the risk free rate, and that the persuasive evidence test does not unduly restrict that discretion. Jemena therefore considers that there is no merit in the AER's proposal to provide additional discretion by removing guidance on how the debt risk premium and the risk free rate should be calculated. Jemena supports additional guidance on how these parameters should be determined, as proposed in the ENA's submission.

Value of precedent

A further reason to retain the current level of guidance on how the debt risk premium and the risk free rate should be set, is the useful precedent on these very issues that has been established through the last round of determinations, including guidance from the Tribunal. Both of these issues are highly technical in nature and, under the current rules, complex technical arguments have been evaluated by both the AER and the Tribunal, resulting in some fairly definitive guidance on the calculation of these parameters. This has introduced a level of certainty and predictability into the regime.

A change to the provisions under which this guidance was provided that results in a higher level of discretion for the AER would greatly reduce (if not entirely remove) the value of the precedent created to date. Therefore, the hard-won credibility of the current regime would be sacrificed. While this is a clear cost of any potential change, it is not clear what benefit is being sought by the AER in making the proposed changes.

The crucial role of merits review

The AER's proposed changes on the cost of capital would have the effect of removing the discipline of merits review on decisions that set key cost of capital parameters, or the methodologies for setting those parameters.

Experience has shown that the AER, as anybody can make errors in its decisions. Many of these errors have been conceded by the AER, while others have been established before of the Tribunal. Errors conceded by the AER include errors in the setting of gamma and the debt risk premium for Victorian distributors. Considering the high value implications of any errors made when calculating the cost of capital, it would be imprudent to remove the key discipline of merits review.

In any case, Jemena believes that any decision regarding the possible expansion, curtailment or removal of merits review is a strategic policy decision that would more appropriately be addressed by the Ministerial Council on Energy and not through a rule change process.

6.6 Costs and benefits

6.6.1 Costs and benefits of making the rule changes the AER has proposed

Given the discussion above, it is clear that the costs of adopting the changes proposed by the AER for the cost of capital would be driven by the reduction in regulatory certainty and stability. The existing framework is stable and fairly predictable, with a body of precedent built up through AER determinations and Tribunal findings under the current rules. Prior to the proposed rule change, regulated businesses had a good idea of the likely outcomes of future cost of capital decisions.

Adopting the wide-sweeping changes would remove that certainty and stability, as it would signal that:

1. Fundamental changes to the regulatory framework can occur less than a full five-year regulatory period after a set of rules is put in place

2. If a regulator is not happy with the outcomes of its own decisions, it can fairly readily have the rules changed to obtain more discretion

3. Any material upward pressure on prices, even if it is well justified through increased investment requirements, is likely to lead to new discretion being provided to the regulator to find a way to reduce prices

All of the above are likely to discourage large scale investment or, at the very least, delay investment. The other reason for the delay is likely to be a “wait-and-see” approach to the new discretion that the AER would obtain under its proposed changes. Investors would need time to observe and understand how the AER would use any such new discretion. As discussed above, a distortion to the timing of investment can lead to a very expensive loss of dynamic efficiency over time, especially when that loss is accrued over both gas and electricity networks.

The following report from Standard & Poor's dated 7 October 2011 highlights the fact that the mere prospect of instability can give rise to investor concern:

> Standard & Poor's Ratings Services today said that the Australian Energy Regulator's (AER) proposed rule changes could increase regulatory uncertainty and heighten adverse credit transition risks for the country's energy network companies. …
>
> The potentially higher regulatory risks, in our view, could make it more challenging for the network sector to attract capital on favorable terms, making it tougher for companies to maintain their financial profiles. This is especially so because of the sector's current and future large capital-expenditure requirement to replace aging network assets, cater for new customer growth, and improve system robustness as Australia moves toward greater reliance on renewable energy sources.
>
> In our view, while each of the proposed rule changes may be incremental and have a minimal impact, overall, they may weaken the network sector's business risk profile. … Moreover, a regulatory regime that periodically introduces changes, in our view, is likely to be a feature of a weaker industry and business risk profile. The uncertainty potentially weakens what have historically been very stable credit metrics, by introducing more volatility into our debt-coverage metric forecasts, particularly when companies are faced with their forthcoming five-year regulatory price reset. As a result, we may expect an increased buffer for a given rating to compensate for any weaker business risk profile.[63]

It is not clear what benefits will be attained through the AER's proposed rule change. They are not well articulated in the AER's proposal. A key benefit to the end user might be lower charges, as the AER uses its additional discretion to provide lower cost of capital allowances. However, if such a reduction in charges distorts investment, it is likely that there will be no net benefit to the economy or consumers in the long term.

6.6.2 Costs and benefits of making the rule changes the EURCC has proposed

Jemena's view of the EURCC proposal is similar to its view of the AER's proposal. The EURCC proposal would also have a destabilising effect on the current regime. Jemena does acknowledge, however, that the cost of debt aspect of the EURCC's proposal does not create additional discretion for the AER.

While under current market conditions it can be argued that a benefit of the EURCC's proposal would be to reduce prices by reducing the cost of debt component of the cost of capital, it is not clear that this would be the case over the

[63] Available at: http://www.reuters.com/article/2011/10/07/markets-ratings-australiaenergyregulator-idUSWNA031420111007, accessed 5 December, 2011.

long term—to the extent that markets settle over time, the forward-looking cost of debt may fall below the embedded (actual) cost of debt as the latter will increasingly reflect the current high cost of borrowing. Also, given the discussion above, focusing on actual rather than efficient costs can lead to distorted investment and dynamic inefficiency not only in the energy network sector, but also in the sectors that rely on services provided by energy networks.

Jemena notes that the ENA, in its submission, suggests that there may be a case for the AEMC to undertake a considered analysis of the matters raised by the EURCC's proposal, and their consequences in the context of the wider WACC framework.

6.6.3 Meeting the NEO and the NGO

Jemena would like to emphasise that both the NEO and NGO focus on the *long term* interests of consumers. These are best served by efficient, timely investment to ensure that the services that consumers need are provided at the required service level and at least cost over the long term.

This objective is best served by a stable, predictable regime that gives investors confidence to make irreversible investments in long-lived assets, without fear of future expropriation of reasonable returns that are required on those assets. Unlike many other producers, an investor in network assets cannot simply pack up and redeploy its network to a different market if the policy conditions of the existing market are suddenly changed in a way that disadvantages the investor.

6.7 The solution

Changes to Part 9 of the NGR

Jemena considers that no changes are needed to Part 9 of the NGR. No evidence has been presented by the AER or the EURCC that there is a problem with the rules framework. Part 9 provides wide discretion to the AER on the cost of capital, which is tempered only by a merits review mechanism and the AER's own desire for consistency with the approach taken to electricity networks—a useful consideration. The results under this framework to date have been reasonable in Jemena's view.

No clear benefits can be derived from destabilising a framework that appears to be functioning well.

Changes to chapters 6 and 6A of the NER

At a first principle level, Jemena supports minimal changes to established well-functioning rules, as this safeguards the certainty and predictability of the regime. Jemena does accept, however, that there may well be a case for incremental improvements to the way the cost of debt parameters are set. These incremental improvements have been proposed by the ENA in its submission.

In principle, Jemena considers that there is no case for material changes to the cost of capital provisions of chapter 6 of the NER (electricity distribution) and that more flexibility is required in chapter 6A (electricity transmission) to ensure that the rules are able to cope with changing market circumstances. Chapter 6A could therefore benefit from mechanisms similar to those in chapter 6, which allows departures from parameters set in the SORI where persuasive evidence exists that such a departure is warranted.

7 The regulatory process for electricity

Key points:

- It is in the interests of all parties that the price review process creates good opportunities for stakeholders to actively engage from the start to the end.
- We can see that when stakeholders actively engage, they can be part of the whole process, have a much deeper level of understanding of the issues, provide meaningful input into the decisions on cost, service and risk being made on consumers' behalf, and the overall outcome of the process will be more robust.
- Improvements in the statutory process can create better opportunities for engagement.
- The AER has raised some valid problems with the process that are worth addressing. In those cases, we build upon many of the AER's proposed changes to suggest more comprehensive solutions:
  - disclosure of all the materials upon which the AER intends to rely for its determinations
  - opportunities and timeframes for stakeholders to review those materials and make submissions
  - treatment of confidential information.

7.1 The current electricity rules

Making submissions on regulatory proposals

Chapter 6 of the current NER:

- allows any person to make a written submission to the AER on an NSP's regulatory or revenue proposal or the AER's draft decision[64]

[64] NER, 6.9.3(c) and 6.10.3(a).

- requires the AER to consider any written submissions (subject to the next item below)[65]
- provides that the AER may, but is not required, to have regard to late submissions[66]
- requires the AER to consider any submissions made on the draft decision, or on any revised proposal submitted[67]

Among the opex and capex expenditure factors, there is a requirement for the AER to have regard to "analysis undertaken by or for the AER and published before the distribution determination in its final form".[68]

Weight that is placed on confidential information in regulatory proposals

Chapter 6 of the current NER:

- allows a DNSP to 'indicate' the parts of its proposal that the DNSP claims to be confidential and wants suppressed from publication on that ground[69]
- requires the AER to publish a regulatory proposal subject to the provisions of the national electricity law and the NER about the disclosure of confidential information[70]
- requires the AER, as soon as practicable after it receives a submission in response to a regulatory proposal or a draft decision, to publish that submission[71]
- requires that the AER must not publish a submission referred to above to the extent that it contains information which has been clearly identified as confidential[72]

[65] NER, 6.10.1

[66] NER, 6.14(a).

[67] NER, 6.11.1.

[68] NER, 6.5.6(e)(3) and 6.5.7(e)(3).

[69] NER, 6.8.2(c)(6).

[70] NER, 6.9.3 and 6.10.3(d).

[71] NER, 6.14(c).

[72] NER, 6.14(d).

- allows the AER to give such weight to confidential information identified in a submission as it considers appropriate, having regard to the fact that such information has not been made publicly available[73].

The framework and approach paper for DNSPs

Chapter 6 of the current NER:

- requires the AER to prepare and publish a framework and approach paper (**F&A paper**) in anticipation of every distribution determination[74]
- requires the AER to commence preparation of, and consultation on, the F&A paper at least 24 months before the end of the current regulatory control period and must complete preparation at least 19 months before the end of that regulatory control period[75]
- requires the AER to set out its "likely approach" in the forthcoming distribution determination, to:
  - the classification of distribution services
  - application of the incentive schemes
  - any other matters on which the AER thinks fit to give an indication of its likely approach[76].

Except for specified matters, a F&A paper is not binding on the AER or a DNSP[77]. For example:

- the classification of services must be as set out in the F&A paper unless the AER considers that, in the light of the DNSP's regulatory proposal and the submissions received, there are good reasons for departing from the classification[78]

[73] NER, 6.14(e). The AER notes that this rule does not cover submissions on revised proposals.

[74] NER, 6.8.1(a).

[75] NER, cl 6.8.1(f).

[76] NER, 6.8.1(b).

[77] NER, 6.8.1(h).

[78] NER, 6.12.3(b).

- the control mechanisms and dual function assets determination must be as set out in the framework and approach paper[79]

- incentive schemes are not specified as matters to be determined by the F&A paper, so the F&A paper's positions on these are not binding.

When the AER can reopen determinations

Chapter 6 of the current NER:

- allows the AER to revoke a distribution determination during a regulatory control period if it appears to the AER that the determination is affected by a material error or deficiency of specified kinds in the NER[80]

- requires the AER, if it revokes a distribution determination, to substitute a determination which only varies from the revoked determination to the extent necessary to correct the relevant error or deficiency[81].

The AER notes that the chapter 6A rules are different in that:

- the AER may only revoke a revenue determination where it appears to the AER that information provided to the AER that was false or misleading in a 'material particular' or there was a material error in the total revenue cap or in the pricing methodology [82]

- if the AER revokes a revenue determination, the AER must make a new revenue determination in substitution for the revoked revenue determination[83]

- if the AER revokes a revenue determination in respect of a material error, the substituted revenue determination must only vary from the revoked revenue determination to the extent necessary to correct the relevant error[84].

Timeframes to make decisions on cost pass throughs, contingent projects and capex reopeners

Chapter 6 of the current NER:

[79] NER, 6.12.3(c)

[80] NER, 6.13(a).

[81] NER, 6.13(c).

[82] NER, 6A.15(a).

[83] NER, 6A.15(b).

[84] NER, 6A.15(c).

- requires that If the AER does not make a determination on a positive pass through amount within 60 business days from the date it receives the DNSP's statement and accompanying evidence, then, on the expiry of that period the amount as proposed is the approved pass through amount[85]

- requires the AER to extend a time limit fixed for determining a positive pass through amount if the AER is satisfied that the difficulty of assessing or quantifying the effect of the relevant pass through event justifies the extension[86].

Similar provisions apply in chapter 6A. Additionally, the chapter 6A rules:

- require the AER to make a decision on the reopening of a revenue determination for forecast capital expenditure within 60 business days of an application being made[87]

- require the AER to make a decision on the amendment of a revenue determination for contingent project(s) within 30 business days of its receipt of an application[88].

Timeframes to review the cost of capital

Chapter 6 and 6A of the current NER:

- require the AER, in conducting a WACC review, to follow the distribution and distribution consultation procedures[89]:

  – first, after publishing a proposed guideline, model, scheme (etc) ,the AER must allow no less than 30 business days for the making of submissions[90]

  – second, within 80 business days of publishing a proposed guideline, model, scheme (etc) ,the AER must publish its final decision on the proposal[91].

[85] NER, 6.6.1(e).

[86] NER, 6.6.1(k).

[87] NER, 6A.7.1(c)(2).

[88] NER, 6A.8.2(d).

[89] For distribution, this is NER, 6.5.4(a).

[90] For distribution, this is NER, 6.16(c).

[91] For distribution, this is NER, 6.16(e)(1).

However, under chapter 6 (but not under chapter 6A):

- the AER may extend the time within which it is required to publish its final decision if (1) the consultation involves questions of unusual complexity or difficulty; or (2) the extension of time has become necessary because of circumstances beyond the AER's control[92]

7.2 The problems

7.2.1 AER's view of the problems

Ability of DNSPs to make submissions

The AER submits that the objective of the current rules has been undermined by DNSPs lodging submissions on their revenue or regulatory proposals (in particular, after their revised proposals). The AER claims that these submissions contain information that should have formed part of their proposals[93]. As a result, the AER says that:

- other stakeholders are denied the opportunity to consider this further information when making submissions to the AER
- the AER's ability to properly assess the further information is impeded[94].

The AER claims that a requirement for it to only consider analysis it is published prior to making a final decision has the potential to make decision-making processes unworkable within the prescribed timeframes. It says it creates a cycle of publishing analysis that would then prompt a submission which in turn requires further analysis and so forth and this would create opportunities for gaming and delay.[95]

Weight that is placed on confidential information in regulatory proposals

In the AER's view, when DNSPs lodge confidential information in a regulatory proposal, the AER is unable to expose that information to public scrutiny and gain stakeholder's informed comment[96].

[92] NER, 6.16(g).

[93] AER Part B (September 2011), p. 85.

[94] The same issue was raised in the AER executive briefing dated 29 September 2011.

[95] AER Part B (September 2011), p. 34.

[96] AER Part B (September 2011), p.90.

The AER has a particular issue with the current chapter 6 and chapter 6A rules in that:

- the current rules do not provide for the AER to exercise its judgment determining the weight that is to be given to confidential information which is provided in a regulatory or revenue proposal
- there is also a degree of uncertainty as to what the expression 'indicates' means in the current rules.[97]

The framework and approach paper for DNSPs

The AER claims three issues with the current framework and approach process, submitting that it:

- results in an inefficient three stage consultation process on the development and application of the incentive schemes in distribution (which the AER suggests could be reduced to two)
- creates the potential for a mismatch between a particular service classification and the form of control to apply to that service
- does not strike the right balance between certainty and flexibility regarding the degree to which service classifications and control mechanisms should be 'locked-in' at the framework and approach stage[98].

When the AER can reopen determinations

While the AER recognises the benefits of being able to correct for material errors, there are three issues which arise under the current rules:

- first, it is conceivable that a material error may arise from errors outside the scope of the prescribed list of errors in chapter 6
- second, the ability in chapter 6A for the final decision to be changed more than the extent necessary to correct an error, where that error is caused by the provision of false and misleading information, has the potential to undermine the finality of the decision making process by reopening matters not necessary for the correction of the error

[97] AER Part B (September 2011), p.90. The rule in question is 6.14(e).

[98] AER Part B (September 2011), pp. 92-93.

- third, in the event an error is to be corrected, it is conceivable there may be circumstances where it is more appropriate or preferable to 'amend' a distribution or transmission determination, rather than to 'revoke and substitute' the entire distribution or transmission determination[99].

Timeframes to make decisions on cost pass throughs, contingent projects and capex reopeners

The AER expects that 60 business days would be an adequate amount of time to assess the majority of pass through applications it might receive. However, for some pass through events, the AER considers a 60 day timeframe will not be adequate to conduct a thorough assessment of the proposal or provide enough time for meaningful stakeholder consultation[100].

Contingent projects and capex reopener assessments also must be completed within relatively short binding timeframes set out in the current rules (60 days and 30 days respectively). While these timeframes will be adequate for some assessments, short timeframes can cause difficulties for complex pass through applications assessments. This is particularly acute for contingent projects where the maximum assessment period in the current rules is only 30 business days[101].

Timeframes to review of the cost of capital

The current rules in chapter 6A contains a 'one-size-fits-all' model where the development or amendment of a guideline, model, scheme or WACC statement must be made within the same timeframe, regardless of the complexity of the task at hand.

The nature and scope of issues with the current rules became apparent during the AER's WACC review:

- this was the first electricity-wide WACC review conducted by an Australian regulator and involved a number of matters of complexity

- the ability for the AER to extend the 80 day timeframe under chapter 6, but not under chapter 6A, placed a practical constraint on the AER utilising the additional flexibility in chapter 6 if the AER was to conduct a joint transmission / distribution WACC review

[99] AER Part B (September 2011), pp 95-96.

[100] AER Part B (September 2011), p. 99.

[101] AER Part B (September 2011), p. 100.

- this restricted the AER's ability to extend the time period for stakeholder consultation much beyond the required minimum period, while at the same time maintain a sufficient period of time for the AER to properly assess the submissions received

- on the other hand, the AER has found the current timeframe rules for the development or amendment of guidelines, models and schemes to be adequate[102].

7.2.2 Jemena's view of the AER problems

Jemena acknowledges that the current rule change proposal offers an opportunity to structure more efficient processes for all stakeholders and contribute to more effective stakeholder engagement.

Ability of DNSPs to make submissions

Jemena's experience demonstrates that the current regulatory process does not provide enough time or opportunity for the AER, DNSPs and other stakeholders to consider all the material the AER may take into account when making its determinations.

DNSPs have had to make submissions after lodging a revised proposal, for a range of valid reasons,[103] and we accept that this has created difficulties for the AER and stakeholders when there is insufficient time to consider and test this new material.

Jemena does not accept that the current requirement for the AER to only consider analysis it has published with no create opportunities for delay or gaming. On the contrary, publication of such analysis should be part of transparent decision-making.

The broader and more significant problem the AER has raised is the need for all stakeholders to have an adequate opportunity to review and comment on all data, approaches and expert reports upon which the AER will rely for its final decision, including analysis conducted by or for the AER itself.

Appendix 1 describes Jemena's experience during JEN's recent electricity price review in Victoria. For its determination, the AER relied on a range of materials

[102] AER Part B (September 2011), pp 97-98.

[103] Reference to ENA submission/expert report.

that had not been exposed to DNSPs or other stakeholders prior to the AER making its final determination.

Good levels of transparency and consultation can enhance the AER's ability to make robust decisions in which all stakeholders can have confidence, and we believe the current regulatory process can be amended to better enable this.

Weight that is placed on confidential information in regulatory proposals

The NER are not deficient in relation to the formal treatment of confidential information. We accept that the AER may be experiencing administrative difficulties dealing with confidential information, which can be remedied in ways other that a rule change.

The NER and the NEL appropriately provide for protection of DNSPs' confidential information, while allowing the AER to test the veracity of confidentiality claims. Where a DNSP seeks confidential treatment of information which, in the AER's opinion, is not genuinely confidential, the AER has a number options including:

- requesting consent from the DNSP to disclose the information (in which case the information may then be disclosed)[104]
- unilaterally deciding to disclose the information if, in its opinion, the detriment arising from the disclosure does not outweigh public benefit[105].

In Jemena's view, the law and rules as presently drafted provide adequate scope for the AER to address a claim for confidentiality of information submitted by all stakeholders, including DNSPs.

Jemena observes:

- A DNSP is compelled (under the rules) to reveal the core of its business by way of extensive information disclosure to the AER, but no other stakeholder is put in this position. It is therefore appropriate that the DNSP should be able to submit confidential information to support its proposal without the prospect of the information being disregarded.
- If the AER believes that additional validation of confidentiality claims is needed in particular cases, it should request that validation at the relevant time. On the other hand, the current rule change proposal would allow the

[104] NEL s. 28X.

[105] NEL s 28ZB.

AER to devalue any submitted confidential information by giving less weight to it at any time the AER chooses.

The framework and approach paper for DNSPs

Jemena agrees with the AER that the framework and approach stage, as currently set out in the rules, has limited utility and could be streamlined. The time and effort currently applied to that stage could be more spent on more productive activities such as earlier finalisation of the RIN.

When the AER can reopen determinations

The prescribed list of errors in chapter 6

NER clause 6.13(a) already provides an adequately targeted list of errors that the AER may correct.

Jemena is comfortable that the current rules preserve the finality of decisions provide certainty for all stakeholders[106] while empowering the AER to re-open a determination if needed.

As described in section 7.2.3 below, Jemena's experience is that the AER has been reluctant to use the opportunities that it has.

Chapter 6A changes to the final decision

Jemena agrees that there is a problem with the chapter 6A provisions for correcting errors in that the AER's capacity to amend or substitute a decision to correct for material errors should be limited to the extent necessary to correct for those errors[107].

To 'amend' a determination rather than 'revoke and substitute'

It is not clear from past experience that the requirement to revoke and substitute has operated as a practical barrier to the AER correcting determinations where errors have been identified. In its submission the AER does not bring forward evidence to suggest that the NER are deficient in this regard..

Accordingly, there is no need for the NER to confer an ability on the AER to 'amend' a determination as well as 'revoke and substitute'.

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[106] AER Part B (September 2011), p. 96.

[107] AER Part B (September 2011), p. 96.

Timeframes to make decisions on cost pass throughs, contingent projects and capex reopeners

Jemena acknowledges that certain pass through assessments in the future may be complex and may need more time for the AER to address them. We agree that the fixed timeframes set out in the NER may not be sufficient in all cases.

Timeframes to review of the cost of capital

Jemena agrees that an inconsistency between transmission and distribution consultation procedures is unnecessary, and may cause difficulties when complex issues are raised in the respective WACC reviews require an extension of time to properly address them.

7.2.3 Analysis of the effectiveness of the current rules over the last five years

Below and in appendix 1, Jemena describes our experience during the 2011-2015 Victorian electricity distribution price review (**EDPR**) and JEN's interaction with the AER.

We conclude that the problems concerning NSP submissions cited by the AER either did not apply to Jemena, or applied only to a minor degree.

Ability of DNSPs to make submissions

The formal AER public consultation began with distributor submissions on the F&A paper and ended with the final decision in October 2010. Appendix 1 sets out in some detail JEN's record of its formal correspondence with the AER until the final decision and beyond.

Appendix 1 indicates:

- JEN engaged with the AER in an extensive consultation process to enable the AER:
  - to develop its framework and approach paper
  - to approve JEN's cost allocation method
  - to develop its RINs.
- For the first RIN, there were three consultations:

- a preliminary draft RIN
- a draft RIN
- a final RIN.

- JEN submitted its initial and revised regulatory proposals by the due dates, and no supplementary submissions were made.
- JEN made a submission on the draft decision by the due date, which contained material unavailable at the time it submitted its revised proposal.
- JEN did not make a submission to the AER on its revised regulatory proposal.
- JEN replied to a multitude AER requests for additional information and requests for further explanation of submitted material. In all, we have identified hundreds of individual emails of correspondence between ourselves the AER in the course of the EDPR.
- After the closing date for submissions, JEN notified the AER that the Commonwealth Bank of Australia had suspended publication of the CBASpectrum fair value curves.
- JEN responded to the AER's consultation paper relating to the treatment of DRP as a consequence of the CBASpectrum fair value curves becoming unavailable.

This sequence of events demonstrates JEN's commitment to actively inform and participate cooperatively in the price review process, and to put information to the AER in the timeliest manner. There is no evidence that JEN strategically withheld information.

Late material relied upon by the AER

For its final determination, the AER relied on substantial additional material that it commissioned after its draft decision and did not make available to stakeholders (including DNSPs) for comment:

- Nuttall Consulting - *capital expenditure report*
- Professor John Handley - *further issues relating to the estimation of gamma*

- Impaq Consulting - *alternative control services report*
- Nuttall Consulting - *scale escalators report 1*
- Nuttall Consulting - *scale escalators report 2.*

The AER might argue that:

- it has to draw a line somewhere on considering material for its final decision
- the materiality of the additional information available to the AER, but unavailable to all stakeholders, needs to be somehow decided
- the regulatory process has defined timelines which should not be extended unnecessarily (within the flexibility available under the rules).

Jemena believes the AER's possible arguments could be accommodated by appropriate changes to the regulatory process including:

- the AER convening a forum to discuss the additional information which is available to it (including third party submissions), and indicating if it might be material information (as it did with the CBASpectrum issue noted in 8.2.3 above)
- allowing stakeholders the opportunity to express their views on additional material (as the AER did with the CBASpectrum issue).

Jemena further submits that complementary procedural refinements which should be considered by the AEMC as rule changes are:

- extending the timeframes for all stakeholders to respond to AER draft decisions, thus allowing stakeholders an adequate opportunity to consolidate their supporting material in reply
- a requirement for the AER to announce when it might decide to adopt a different approach, data or expert report to that previously indicated, and to consult on that different approach.
- a time period in the regulatory process for stakeholder to cross-submit on one another's submissions
- a requirement that "completeness" in NSP submissions should also apply to AER draft decisions.

Weight that is placed on confidential information in regulatory proposals

Necessarily, the AER is asked to consider large amounts of confidential information in price reviews and the challenge for the AER was to manage this during the Victorian distribution price review given that 5 DNSPs were involved.

It is likely that each business identified its confidential information and presented it to the AER in a different manner. This must have created administrative difficulties for the AER.

We also understand that consumer groups have concerns about information that the business identify as confidential.[108]

The framework and approach paper for DNSPs

JEN's experience in the recent EDPR highlights some difficulties with the F&A paper process.

In its original regulatory proposal, JEN did not agree with the AER's F&A paper classification of aspects of new connection and augmentation services as negotiated distribution services. In its regulatory proposal, JEN proposed to classify all new connection and augmentation works as standard control services.

In the draft decision, the AER accepted JEN's proposed classification of new connection and augmentation services as standard control services, with the exception of routine connection services which the AER classified as alternative control services. As a practical matter, JEN accepted the draft decision in its revised regulatory proposal while not agreeing with the reasoning for and the appropriateness of the AER's service classification[109].

In Jemena's view, the F&A consultation added little value to the preparation of JEN's regulatory proposal in respect of service classification. JEN disagreed with aspects the F&A paper service classifications and the AER eventually accepted (most of) JEN's classifications.

When the AER can reopen determinations

After its final determination on 29 October 2010, the AER had the opportunity to reopen it to correct for two arithmetic errors and avoid merits review of them. In Jemena's view the current rules would have enabled this.

[108] May Mauseth Johnston, *Barriers to fair network prices*, A report prepared for the Consumer Action Law Centre and the Consumer Utilities Advocacy Centre, p. 54.

[109] Jemena Electricity Networks (Vic) Ltd, *Revised regulatory proposal*, 20 July 2010, pp 15-16.

Following the AER final decision, JEN had three weeks to determine if the AER had made any errors, whether the AER would be willing to correct those errors, and, if not, to lodge an application for merits review to the Tribunal.

JEN identified two errors in the AER's calculation of the debt risk premium (**DRP**): one relevant to all the Victorian DNSPs, and one relevant only to JEN.

The chronology of subsequent events was as follows:

- Week 1 – JEN advised the AER by email on 1 November 2010 of its initial concerns on the DRP calculation, and sought copies of the information and models the AER relied on. The AER responded that day by email with its WACC spreadsheets.

- Week 2 – JEN confirmed the errors and consulted the other Victorian DNSPs. JEN formally advised the AER on 11 November 2010 by letter that it had identified the two errors and requested the AER's agreement to revoke its determination to correct the errors.

- Week 3 – The AER declined to respond to JEN's request. JEN applied for leave for merits review of the AER's decision on grounds including those related to the two DRP errors.

- Two months later – JEN confirmed with the AER its desire to resolve the two DRP errors outside the merits review process. The AER replied that it did not consider appropriate to apply rule 6.13 to either of JEN's DRP points.

- Four months later – In its submission-in-reply to the Tribunal, the AER conceded both DRP errors and the Tribunal will determine the outcome.

Jemena submits that the outcome of the above process demonstrates that, if the AER had used its rule 6.13 powers to amend the errors, then an appeal to the Tribunal on those grounds could have been avoided to the benefit of both the AER and Jemena, and ultimately consumers.

It is not clear why the AER should seek to broaden its power to reopen decisions when it is reluctant to use the power it has.

7.3 Prescription and discretion

7.3.1 AER's proposed rule change

Ability of DNSPs to make submissions

The AER's proposes to:

- restrict a DNSP or transmission network service provider (**TNSP**) from making a submission on its own regulatory or revenue proposal and where there are concurrent proposals being assessed, on another DNSP's or TNSP's regulatory or revenue proposal unless there are material differences between the two.

- provide for the AER not to consider submissions which do not comply with the restrictions or late proposals[110].

At the same time, the AER proposes to remove two expenditure factors—6.5.6(e)(3) and 6.5.7(e)(3)—that the AER says require it to only consider its own analysis if it is published prior to the making of the final determination.[111]

Weight that is placed on confidential information in regulatory proposals

The AER's proposed solution (for DNSPs) is to:

- require a DNSP to identify the confidential parts of a regulatory proposal or a revised regulatory proposal;

- remove the reference to the parts of the proposal that the DNSP wants suppressed, which is redundant; and

- introduce new clauses to provide for the AER to give such weight it considers appropriate to confidential information in a regulatory proposal or a revised regulatory proposal[112].

A similar proposal applies for TNSPs.

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[110] AER Part B (September 2011), p. 88.

[111] AER Part B (September 2011), p. 34.

[112] AER, *Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules,* Part C – Draft Rules, September 2011, table 1.11, p. 10.

The framework and approach paper for DNSPs

The AER proposes to:

- provide for the AER to change the classification of services or the control mechanism from that specified in the framework and approach paper if unforeseen circumstances arise from the regulatory proposal and submissions received

- remove the requirement for the AER to state its likely approach to the application of incentive schemes[113].

When the AER can reopen determinations

The AER's proposed rules would:

- remove the matters listed in chapter 6 from which a material error may arise

- provide for the AER to amend, in addition to revoke and substitute, distribution and transmission determinations

- require that all material errors only be corrected to the extent necessary[114].

Timeframes to make decisions on cost pass throughs, contingent projects and capex reopeners

The AER proposes that it would be required to make determinations on positive pass through amounts, negative pass through amounts, contingent projects and capex reopeners within 40 business days of receipt of an application.

However, the AER would have the power to extend this timeframe up to an additional 60 business days if:

- the assessment involves questions of unusual complexity or difficulty, or

- the AER requires information further than that submitted by the NSP in its application[115].

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[113] AER Part B (September 2011), p. 94.

[114] AER Part B (September 2011), p. 96.

[115] AER Part B (September 2011), pp 100-101.

Timeframes to review of the cost of capital

The AER proposes a revision to:

- provide that a [WACC] review is to be must be undertaken in accordance with the distribution consultation procedures, subject to the reference in rule 6.16(e) and 6A.20(e) to 80 business days being read as a reference to 100 business days, and
- the AER is not able to extend the time within which it is to make the final decision under rule 6.16(g).

7.3.2 The right balance between prescription and discretion

In general, the rules need to prescribe a standard process in which the AER, DNSPs and stakeholders all have enough time and opportunity to contribute to the decision making process effectively.

Beyond that, the AER needs discretion to extend or vary that process, but only to deal with unexpected or uncertain circumstances within the boundaries of best regulatory practice and the need for investment certainty.

7.3.3 Do the proposed rules achieve the right balance?

For the reasons we discuss in section 7.4, some of the AER's proposed changes achieve the right balance and some of them do not.

7.4 AER's use of its discretion

7.4.1 Do the AER's proposed rules give the AER greater discretion?

Ability of DNSPs to make submissions

The AER's changes proposed for NSP submissions will significantly reduce the AER's discretion to properly take account of important information DNSPs may submit. By doing so, they do not adequately address the real problem.

In any case, the NER currently allow the AER to take into account late submissions, but it is not required to. Under the AER's proposals, it **must not** consider submissions or proposals that are late or otherwise do not comply with NER requirements.

Jemena considers that limiting the AER's discretion in this manner is entirely unnecessary and would prove to be counterproductive. The AER currently has discretion to either not consider late material or give it less weight in making a determination. This discretion is necessary given the possible need for NSPs or other stakeholders to make late submissions in circumstances such as those noted in section 7.2.2 above.

The greater prescription proposed by the AER will not improve the regulatory process and will only increase the risk of regulatory error. Prohibiting the AER from considering late submissions will preclude any opportunity for the AER to consider new information submitted after the revised proposal, despite the possible high relevance of that information to AER decision making.

Weight that is placed on confidential information in regulatory proposals

The AER is proposing to enshrine in the NER more discretion in dealing with confidentiality claims.

As noted in section 7.2.2 above, a NSP is compelled (under the rules) to reveal the core of its business by way of extensive information disclosure to the AER, but no other stakeholder is put in this position. It is therefore appropriate that the NSP should be able to submit confidential information to support its proposal without the prospect of the information being disregarded. Confidential information is not a matter of choice for the NSP.

Increasing the AER's discretion simply opens the prospect of the AER ignoring significant information that it should have regard to and will not reduce the amount of NSP information that is regarded as confidential.

The framework and approach paper for DNSPs

The AER is proposing greater discretion to determine the scope of the F&A paper.

Considering the range of issues identified by the AER, Jemena considers that even greater discretion could be given the AER and DNSPs to both initiate and reduce the scope of the F&A paper.

When the AER can reopen determinations

The AER's proposal would significantly increase uncertainty around when the AER may seek to exercise any discretion to amend a determination by allowing amendment for any "material error or deficiency" with no indication given of what the term "deficiency" is intended to cover. Potentially, it could cover anything in a determination which the AER regards as a shortcoming in its analysis, reasoning or assessment of inputs.

A potential unintended consequence of the AER's proposal would also be that it could revoke and substitute determinations that it has already made (that is, determinations currently in force). This creates a highly unacceptable level of risk for businesses.

Jemena agrees with the AER that it is vital to balance a need for discretion to correct errors with the need to preserve the finality and certainty of the final determination. The current provisions of chapter 6 dealing with correction of errors provide this balance. Clause 6.13(a) offers a clear and targeted list of errors that may be corrected for, while preserving the finality of the determination. Any expansion of the existing AER discretion which weakens finality and certainty would not be appropriate.

Timeframes to make decisions on cost pass throughs, contingent projects and capex reopeners

While agreeing with the AER that the fixed timeframes set out in the NER may not be sufficient in all cases, Jemena considers that the AER's proposed solution does not adequately address the problem it has identified.

While the AER proposes to have broad discretion to extend the assessment timeframe out to 100 days, there would be no scope to extend beyond this in cases of particular complexity or where the AER needs to await further information.

If an extension of timelines required when the AER is awaiting further information or the completion of an associated process, a simple extension to 100 days may not be sufficient. Jemena agrees with the ENA's suggestion that a more targeted 'stop-the-clock' mechanism is likely to be more useful in these circumstances.

Timeframes to review of the cost of capital

Jemena agrees with the AER proposal that the timeframe between draft and final decisions be capped at 100 days. Whilst it is important for the AER to consider all evidence as part of its review, it is equally important that NSPs have certainty as to when a final determination will be made.

The AER also has discretion to engage in extensive consultation prior to issuing a draft decision. By introducing further consultation steps, the AER could identify key issues and areas of disagreement and thereby make it easier to achieve the 100 day maximum target for a final decision

7.4.2 *Could the AER achieve the same outcomes through greater use of the discretions it already has?*

Potentially, in relation to confidential information and reopening determinations, the AER can already achieve the outcomes it intends using its existing discretions.

7.5 Costs and benefits

7.5.1 *Costs and benefits of making the rule changes the AER has proposed*

In Jemena's view, there are significant costs in accepting the AER's proposed rule changes in respect of:

- ability of NSPs to make submissions on their own regulatory proposals
- weight that is placed on confidential information in regulatory proposals
- when the AER can reopen determinations.

All these proposals narrow the scope of the current rules provisions, potentially creating greater uncertainty in the regulatory process, with attendant higher costs.

On the other hand, Jemena considers that there would be net benefits in the following AER proposals—subject to any qualifications Jemena has already made above:

- the framework and approach paper for DNSPs
- timeframes to make decisions on cost pass throughs, contingent projects and capex reopeners
- timeframes to review of the cost of capital.

In Jemena's view, these proposals would give more flexibility to the regulatory process, with resulting benefits to all stakeholders.

7.5.2 *Meeting the NEO and the NGO*

In Jemena's view, the first three proposals listed in section 7.5.1 above would not, on balance, contribute to the NEO. The last three proposals would contribute to the NEO by assisting the AER to arrive at timely and well considered decisions.

7.6 The solution

7.6.1 Are there more appropriate solutions to the problems that exist?

Ability of DNSPs to make submissions

Jemena agrees with the ENA's suggestion that an alternative means of promoting greater stakeholder involvement would be to introduce a process of submissions and cross-submissions on the draft decision and revised regulatory proposal. This would allow stakeholders to consider and comment on any further submissions made by the NSP and would allow the NSP to respond to any submissions made by third parties on its revised proposal.

At the same time, the AER would still need to have discretion in evaluating its treatment of late submissions.

Weight that is placed on confidential information in regulatory proposals

Jemena submits that the NER are not deficient in relation to the treatment of confidential information, and do not need revision. The AER can use its already adequate powers to achieve its objectives of discouraging illegitimate confidentiality claims and allowing for testing of information subject to such claims.

Rather than a rule change, we suggest this problem could be addressed in the first instance at a stakeholder forum prior to the commencement of the next review process. At the forum, DNSPs, the AER and other stakeholders could raise their issues and concerns about how confidential information is identified, verified and take into account. With a better level of understanding among the parties of their concerns and aspirations, Jemena is confident that many their issues can been resolved.

The framework and approach paper for DNSPs

Jemena agrees with the ENA's suggestion that the F&A paper be made optional under the NER, and would be initiated by either the AER or the NSP as considered necessary. If the F&A process was not initiated by either party then it could be bypassed altogether, and the status quo would be maintained in terms of control mechanisms, service classifications and application of incentive schemes.

When the AER can reopen determinations

Jemena considers that the AER's current level of discretion is well balanced to address errors requiring correction in final determinations, while still providing certainty in AER decision making. Jemena notes that this discretion is yet to be used by the AER.

Timeframes to make decisions on cost pass throughs, contingent projects and capex reopeners

Jemena proposes an alternative “stop the clock” mechanism, whereby the AER may stop the clock on an application if it needs to seek more information, consult with stakeholders or await the outcome of a related process (e.g. the Victorian Bushfires Royal Commission).

Jemena submits that this approach is more targeted at the AER’s concerns and would offer less scope for the AER to extend timelines without clear reference to a specified and significant external event.

Timeframes to review of the cost of capital

Jemena agrees with the AER proposal that the timeframe between the draft and final WACC decisions be capped at 100 days.

8 Treatment of shared electricity assets

Key points:

- There are certain circumstances where electricity consumers are entitled to some compensation where DNSPs use regulated assets to earn unregulated revenue.
- The AER proposed rule changes are too prescriptive and will not deal appropriately with the issue of shared assets.
- Jemena proposes an alternative solution.

8.1 The current rules

The current rules do not allow the AER to make a revenue adjustment for the use of standard control assets in the provision of other services, including unregulated services.

An exception is in Queensland where a mechanism developed by the Queensland Competition Authority (**QCA**) was preserved under the transitional provisions in the NER.

8.2 The problem

8.2.1 AER's view of the problem

The AER submits[116]:

- The current rules result in standard control service consumers paying for 100 per cent of the costs of an asset, but receiving no compensation when the same asset is used by the service provider in undertaking other activities.
- Consumers that used to benefit under state based regulatory arrangements are no longer able to receive any compensation.

[116] AER Part B (September 2011), p. 59.

8.2.2 *Jemena's view of the problem*

Jemena acknowledges that assets included in the regulatory asset base (RAB) can be used in provision of services other than standard control services and that, under specific circumstances, electricity consumers can be entitled to compensation where DNSPs use regulated assets to earn unregulated revenue.

However, the problem of designing an appropriate regulatory regime for capturing (net) revenues arising from the use of shared assets is more complex than that described by the AER. The extent to which standard control service consumers should expect to benefit from the use of assets for the provision of unregulated services will be influenced by a number of factors.

At one end of a spectrum, the uncertainty as to the potential for any (net) revenues to be realised in a forthcoming regulatory period may be sufficiently great, the materiality of those revenues may be sufficiently small, and/or the degree of innovation as to their source may be sufficiently high that it is simply not appropriate for any regulatory intervention to occur at all.

At the other end of that spectrum, there may be circumstances where such revenues are stable and ongoing, and ubiquitous across DNSPs, so that it is appropriate for some sharing with consumers to occur.

8.2.3 *Analysis of the effectiveness of the current rules over the last five years*

This has been a jurisdictional issue in Queensland and South Australia, rather than a national issue.

However, the AER submits that the use of existing poles and pits to provide access for NBN services will be a national issue. While the activities may be covered by the existing approach to the use of shared assets in Queensland, DNSPs in other jurisdictions are not required to share any additional revenues they earn from facilitating NBN services through the use of shared assets[117].

[117] AER Part B (September 2011), p. 59.

8.3 Prescription and discretion

8.3.1 AER's proposed rule change

The AER proposes (for DNSPs) to include a revenue adjustment or mechanism for situations where shared assets are used for non-standard control services, including unregulated services. Specifically, revisions to[118]:

- introduce a new clause to allow for any revenue decrement for that year arising from;
- introduce a new clause to provide for the AER to set out in the framework and approach paper its likely approach to; and
- to require the AER to make a constituent decision in relation to the use or forecast use of assets forming part of the regulatory asset base for the provision of services other than the provision of standard control services.

The AER's discussion of the issue suggests that it has two types of adjustments in mind to capture some of the benefit of revenue from shared assets[119]. These are:

- adjustments to the revenue requirement calculation, to be applied when reasonable forecasts of asset use can be made, or
- adjustments to the price control mechanism that establish an ex ante sharing mechanism for profits arising from the use of shared assets. This would be applied where forecasting is problematic (or not possible), and would be applied ex post, possibly during the annual price approval process.

The AER mentions (in a footnote) that a revenue adjustment could include an unders and overs adjustment for any difference between forecast and actual use of assets[120]. However, this is not specified in the rule change proposal.

The AER states that it would be desirable that the AER have the ability to adopt the most appropriate approach based on the circumstances it encounters[121].

[118] AER Part B (September 2011), p. 60.

[119] AER Part B (September 2011), pp 60-61.

[120] AER Part B (September 2011), p. 60.

[121] AER Part B (September 2011), p. 60.

8.3.2 *The right balance between prescription and discretion*

In Jemena's view, the right balance between prescription and discretion would have the following outcomes:

- there would no impediments to DNSPs having incentives to actively seek new forms of unregulated services which would utilise regulated assets
- it would be clear under what circumstances revenue sharing between DNSPs and electricity consumers was appropriate
- there would be some guiding principles which would govern the basis for deciding the amount of revenue to be shared with consumers.

8.3.3 *Do the proposed rules achieve the right balance?*

Jemena considers that the AER proposed rule changes do not provide a right balance between discretion and prescription.

In our view, the proposed rule changes provide the AER with too much flexibility in relation to the treatment of shared assets.

8.4 AER's use of its discretion

8.4.1 *Do the AER's proposed rules give the AER greater discretion?*

Currently, the AER has no discretion under the rules to address shared assets.

As mention in section 8.3.3 above, the proposed rule changes provide the AER substantial new flexibility in relation to the treatment of shared assets. The two types of adjustment proposed are also likely to involve significant practical complications, with the risk that for embryonic forms of unregulated services, the extent of sharing and the associated regulatory burden will impose a substantial disincentive for DNSPs to get involved in providing these services.

The rationale for the AER having largely unfettered discretion to adopt the most appropriate approach given the circumstance is not justified—the AER effectively suggests that the decision as to the nature and form of mechanism to be applied depends only on the ability of DNSPs to forecast revenue from the provision of unregulated services.

For example, there is no recognition that the use of an unders and overs adjustment (which is indicated as a possibility by the AER) to account for any difference between the forecast and actual use of assets is likely to reduce significantly the incentive for DNSPs to exceed the forecast by entering into additional shared asset arrangements. This is an undesirable consequence.

The rule change options presented by the AER amount only to potential sharing mechanisms, and involve no recognition of the basic question of whether any sharing is appropriate and, if so, by what means and how much.

8.4.2 Could the AER achieve the same outcomes through greater use of the discretions it already has?

No. Currently, the AER has no discretion under the rules to address shared assets.

8.5 Costs and benefits

8.5.1 Costs and benefits of making the rule changes the AER has proposed

Jemena recognises that the case for some form of 'regulatory appropriation' of part of the revenue arising from DNSP provision of other services that utilise standard control assets is not without economic merit. However, there are costs that need to be considered when making the case for intervention, in particular whether intervention will negate incentives for DNSPs to actively seek and develop unregulated services.

8.5.2 Meeting the NEO and the NGO

The extent to which the NEO establishes a case for regulatory intervention to establish a form of revenue sharing depends upon the particular circumstances applicable to each relevant DNSP.

8.6 The solution

8.6.1 Are there more appropriate solutions to the problems that exist?

Jemena wishes to draw the AEMC's attention to the potentially very wide range of circumstances that may apply when regulated assets are used to provide unregulated services. The rule change options presented by the AER amount only to potential sharing mechanisms, and involve no recognition of the basic question of whether any sharing is appropriate and, if so, by what means and how much.

Assuming however that the principle is accepted that some sharing with electricity consumers of the net revenues arising in the provision of unregulated services that use standard control assets is appropriate, Jemena emphasises that a set of principles should be developed to guide AER decisions in this area.

In our opinion, those principles should provide that any sharing arrangement must:

- apply only to revenues after netting off all relevant costs, including the risks associated with the use of standard control assets
- take into account the detrimental effect of any form of sharing on the incentives of DNSPs to develop such alternative sources of revenue
- be developed so as to minimise the associated regulatory burden
- be applied in such a way that new forms of unregulated service are granted a sharing holiday for, say, a minimum initial period – of perhaps 3 or 5 years
- provide a basis for deciding the amount of revenue to be shared with consumers
- disregard services that are unlikely to be material
- be designed so as to be proportionate to the amounts involved.

Additionally, Jemena submits that the default approach to the sharing of (net) unregulated revenues from standard control assets should be by way of an annual revenue forecast, perhaps with an ex post true up (which could be done in the following regulatory control period).

The AER specifically cites the NBN rollout as a reason for proposing this rule change. Given that the use of poles, wires and ducts for cable purposes is extremely likely to involve an annual rental which can be easily forecast, adjustments to the revenue requirement calculation should be preferred over potentially complex adjustments to the price control mechanism.

Appendix 1

JEN CORRESPONDENCE WITH AER IN 2011-15 EDPR

Nature of correspondence	Date submitted	Date due	Comment
AER Framework and Approach paper for Victorian electricity distribution regulation - Regulatory control period commencing 1 January 2011: • JEN submission on preliminary positions paper	13 March 2009	6 March 2009	AER published preliminary positions paper (PPP) for its framework and approach paper for Victorian DNSPs on 19 December 2008 JEN met with AER to discuss PPP on 19 February 2009 Final Framework and Approach paper issued in May 2009
JEN cost allocation method (**CAM**) (The AER is required to approve a proposed CAM under the NER)	Various		AER had a preference for DNSP's to submit their CAMs before 30 Nov 2009 but recognised that DNSP's were not obligated to do so. The AER approved JEN's CAM on 26 February 2010.
First regulatory information notice	30 Nov 2009	30 Nov 2009	JEN's extensive RIN consultation and submission process with AER: • 24 April 2009 – AER commenced consultation on preliminary draft RIN and templates • 10 August 2009 – AER commenced consultation on draft RIN and templates • 14 October 2009 – AER sent final RIN to JEN.

Nature of correspondence	Date submitted	Date due	Comment
Regulatory proposal (confidential) Regulatory proposal (public)	30 Nov 2009 4 Dec 2009	30 Nov 2009	108 individual items submitted 22 individual items submitted
Correspondence between AER and JEN re JEN submissions	21 July 2009 to 19 Nov 2010		JEN and the AER exchanged hundreds of individual emails. Matters dealt with included: ▪ Additional information sought by AER ▪ Explanations ▪ Clarifications ▪ Reconciliation of data ▪ Additional spreadsheets and calculations ▪ Additional documents ▪ Assumptions and evidence ▪ Confirmation of data
AER draft decision		4 June 2010	Reports accompanying draft decision: ▪ ACIL Tasman final report ▪ Access Economics report ▪ Impaq Consulting final report ▪ Prof McKenzie and Associate Prof Partington report ▪ Associate Prof Handley report ▪ Nuttall Consulting final report

Nature of correspondence	Date submitted	Date due	Comment
JEN submission on draft decision	19 Aug 2010	19 Aug 2010	JEN set out additional material that it believed was relevant to the AER's final determination in relation to: ▪ the bushfire pass through event ▪ new electricity safety regulations ▪ the value of imputation credits (gamma).
JEN revised regulatory proposal (confidential) JEN revised regulatory proposal (public)	20 July 2010 23 July 2010	21 July 2010	172 individual items submitted 87 individual items submitted
Submissions on revised regulatory proposals		**19 August 2010**	
JEN response to stakeholder submissions	24 Sept 2010		Matters dealt with: ▪ public lighting ▪ benchmarking and debt risk premium ▪ JEN's maximum demand forecasts ▪ cost pass through ▪ premium feed-in tariffs, a side constraint, and rolling capital expenditure into the regulatory asset base

Nature of correspondence	Date submitted	Date due	Comment
Update on DRP and the CBA-Spectrum fair value curves	13 Sept 2010		In response to the draft decision JEN sought to provide material that had only recently become available to JEN (13 September). JEN considered that the notification from the Commonwealth Bank of Australia (CBA) was material that was directly relevant to the AER's decision on the measurement of the debt risk premium (DRP) that would apply in JEN's distribution determination. JEN requested the AER to consider this notice as part of JEN's revised regulatory proposal.
AER consultation on CBASpectrum – Victorian DBs made series of joint submissions to the AER in October 2010			On 27 September the AER issued a further consultation paper relating to the debt risk premium, in response to CBASpectrum's ceasing publication of its fair value estimates and the decision of the Australian Competition Tribunal in the ActewAGL matter (ACT 1 of 2010) handed down on 17 September 2010. The AER also published a report from Bruce Mountain entitled *Response to the distributors' "Submission in response to the Mountain Report on DRP"* (October 28, 2010).
AER final decision		**31 October 2010**	New and/or expanded material was included in the following reports accompanying the final decision: ▪ Nuttall Consulting - capital expenditure report ▪ Professor John Handley - further issues relating to the estimation of gamma ▪ Impaq Consulting - alternative control services report ▪ Nuttall Consulting - scale escalators report 1 ▪ Nuttall Consulting - scale escalators report 2

9 Appendix 2 (Glossary)

ACT (or Tribunal)	Australian Competition Tribunal
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CAPM	capital asset pricing model
DMIS	demand management incentive scheme
DNSP	distribution network service provider
EBSS	efficiency benefit sharing scheme
DRP	debt risk premium
EDPR	electricity distribution price review (Victoria)
ESCV	Essential Services Commission of Victoria
ENA	Energy Networks Association
EURCC	Energy Users Rule Change Committee
F&A paper	framework and approach paper (issued by the AER)
gamma	the assumed value of imputation credits
JEN	Jemena Electricity Networks (Vic) Ltd
JGN	Jemena Gas Networks (NSW) Limited
MRP	market risk premium
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NGL	National Gas Law

NGO	National Gas Objective
NGR	National Gas Rules
NSP	network service provider
EURCC	Energy Users Rule Change Committee
opex	operating expenditure
PTRM	post tax revenue model
PV	present value
RAB	regulatory asset base
RFM	roll forward model
RIN	regulatory information notice (issued by AER)
SORI	(AER) Statement of Regulatory Intent (on WACC)
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
Tribunal (or ACT)	Australian Competition Tribunal
WACC	weighted average cost of capital

Victorian domestic electricity prices 1996-2010: The contribution of network costs

A report for the Victorian electricity network businesses

9 September 2011

Ernst & Young

Contents

1. Executive summary

Ernst & Young was engaged by the Victorian electricity network businesses to:

- Conduct an independent analysis of the trend in Victorian electricity prices over the medium term;
- Disaggregate the trend to examine the role of network costs in the changes in Victorian electricity prices; and
- To the extent possible, compare the results with those observed in other Australian jurisdictions.

This report provides the outcome of our work.

1.1 Approach

Analysing electricity prices over long periods of time presents a number of challenges due to changes in industry structure, ownership, information gathering processes and publication, the technology employed, the number and structure of tariffs over time, consumer behaviour and the tax system (e.g. the introduction of the Goods and Services Tax (GST) and the easement land tax paid by the Victorian transmission business).

The Australian Bureau of Statistics (ABS) produces an electricity price index (*ABS Consumer price index, catalogue no.6401.0 Table 13*) for each capital city[1] that commences in 1980 and shows the trend in electricity prices since that time. We have used that index in our analysis. The ABS does not however disaggregate the index into the components that make up the final retail electricity price.

To analyse the trend in Victorian electricity prices over the medium term, we have relied mostly on a bottom up approach as it uses the actual retail and network tariffs paid by customers. In particular, we have examined the historical trend of annual electricity costs for the typical domestic customer[2] from 1996 to 2010 (excluding GST)[3] and have disaggregated the trend down to the network and non-network components of retail electricity prices for each distributor. We have then averaged the results to provide State-wide results.[4]

Network costs (NUOS) have been disaggregated into distribution use of system costs (DUOS) and transmission use of system costs (TUOS). We have included the cost of the advanced metering infrastructure (AMI) or "smart meter" costs in the network component.[5]

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[1] While the ABS produces its electricity price index (which forms part of its Consumer Price Index) for each State and Territory capital city, the index is widely assumed to be representative for the whole State or Territory. In this instance, the ABS electricity price index for Melbourne is assumed to be broadly representative of domestic electricity prices in Victoria.
[2] The typical domestic customer is defined as a customer under a domestic single rate tariff with an average consumption profile throughout the period of analysis (i.e. consuming average consumption volumes in each year from 1996 to 2010. State-wide average consumption data sourced from the ESAA's annual Electricity Gas Australia publications). See Section 3 and Appendix A for more details.
[3] 1996 was the first year when prices charged by Victorian electricity network businesses were separately regulated following a broader industry restructure. There are thus significant limitations on data availability prior to this.
[4] The State-wide average is calculated as the average of the five distribution network businesses, weighted by volume or MWh distributed.
[5] Advanced metering infrastructure costs capture the costs reflected in the previous Victorian Government's decision to roll out 'smart meters' for all small users. In 2006-09, advanced metering charges for these businesses were subject to a separate pricing schedule approved and published by the ESC. From 2010, advanced metering charges for the Victorian electricity network businesses are determined by a separate regulatory decision by the AER. In practice, it includes some metering costs that would have been incurred absent the roll out.

Non-network costs refer to all costs involved in the supply of electricity other than distribution and transmission use of system charges (i.e. network costs) and includes costs such as wholesale energy costs and retail margins.

We have assumed the single rate tariff is representative of typical domestic electricity prices, as over 90 per cent of domestic electricity customers in Victoria pay this tariff.[6]

We have not analysed the cost of electricity in the business or non-domestic sectors because a similar analysis using the actual tariffs paid by these customers is not feasible for several reasons, including data limitations, the large number and complex structure of non-domestic tariffs and the prevalence of individually negotiated "non-standard" contracts.

Between 1996 and 2010, on average, domestic customers accounted for approximately 29 per cent of total demand in Victoria and around 88 per cent of customers by customer numbers.

All the data used in our analysis is publicly accessible. To validate our analysis, the Victorian electricity network businesses provided confidential data on customer numbers and average consumption by tariff type and SP AusNet provided data on costs associated with the easement land tax. However this data has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

We have further verified our results by, amongst other things, comparing the findings derived from the analysis described above:

- With the results of our disaggregation of the ABS electricity price index for Melbourne (the top down approach), which uses aggregated industry data rather than actual tariffs paid by customers; and

- With the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors).[7]

We have also adopted the approach described above to disaggregate the change in annual electricity costs in NSW and Queensland.

1.2 Our results

Our analysis shows that:

- Electricity prices and typical bills for the typical domestic customer in Victoria have increased by 7 per cent in real terms from 1996 to 2010. However since 2007, domestic electricity prices have increased by 30 per cent in real terms. This followed a decrease in domestic electricity prices of 18 per cent in real terms between 1996 and 2007; and

- The increases in domestic electricity prices in Victoria cannot be explained by increases in network costs (i.e. the sum of distribution and transmission use of system charges).

Figure 1 illustrates what has happened to the relevant components of average Victorian electricity prices in real terms over the period 1996 to 2010. It separates retail prices into network costs and non-network costs (i.e. wholesale energy costs and retailers' costs), and network costs into distribution use of system costs and transmission use of system costs.

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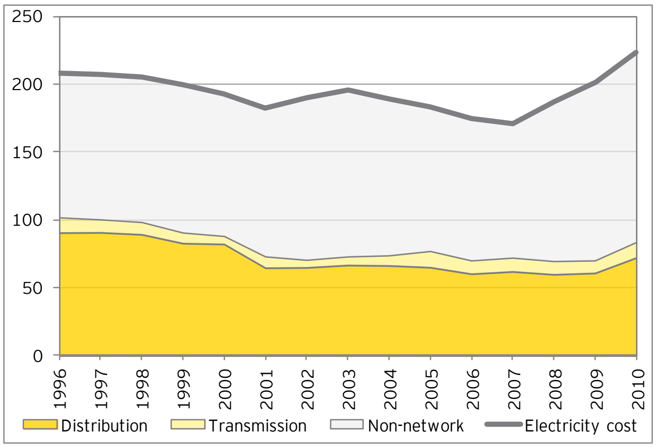
[6] Data made available to us suggests that 90% of domestic electricity customers in Victoria are under a single rate tariff based on data on domestic customer numbers by tariff type provided by the Victorian electricity network businesses.

[7] Determinations made under the Victorian Tariff Order 1995, and distribution determinations made by the ORG, ESC and AER. See Appendix B for details.

Figure 1 Victoria electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

Figure 1 shows that network costs per megawatt-hour (MWh) in Victoria have fallen by 18 per cent in real terms between 1996 and 2010. On a per customer basis, network costs have decreased by 9 per cent in real terms. The difference reflects the increase in average consumption during this period.

Table 1 below shows the results numerically.

Table 1 Change in average annual Victorian electricity costs from 1996 to 2010 (real 2010)

	Percentage change		Dollar change	
	per MWh	per customer	per MWh	per customer
Final retail price	+7%	+19%	+$15	+$201
Network	-18%	-9%	-$18	-$46
Non-network	+31%	+45%	+$33	+$247

Source: Ernst & Young analysis

Disaggregating network costs between the distribution and transmission elements reveals annual distribution network costs between 1996 and 2010 have decreased to a greater extent than total network costs. Between 1996 and 2010:

- Distribution use of system costs have decreased by 20 per cent in real terms; and
- Transmission use of system costs have increased by 2 per cent in real terms, but have been driven higher by other factors and are quite volatile, for reasons described in Section 4.1.1.[8] For example, if the easement land tax was not paid by the transmission business in Victoria, transmission costs would also have fallen significantly, by as much as 18 per cent in real terms during this period.

In contrast, non-network costs increased by 31 per cent in real terms between 1996 and 2010.

In other words, for the typical domestic customer, annual network costs in Victoria have decreased in real terms between 1996 and 2010:

- On a per MWh distributed basis;
- On a per customer basis;
- Including AMI costs as a result of the previous Victorian Government's mandated roll out of AMI; and

[8] Figures may be affected by rounding.

- In excess of the benefits that may reasonably be expected from load growth (refer to Section 4.1.4).

Based on our analysis, none of the increases in electricity prices in Victoria over the 1996 to 2010 period can be attributed to network costs. Some of the increases in electricity costs from 2006 can be explained by the AMI roll out.

1.2.1 Consistency of results

We have validated our bottom up findings with the results from an analysis of the trend in Victorian domestic electricity prices achieved by disaggregating the ABS electricity price index for Melbourne[9] (i.e. the top down approach), which uses aggregated industry data rather than actual tariffs paid by customers. The top down approach produces similar outcomes in terms of the performance of network costs, but we have greater confidence in the results using our bottom up approach because they rely on actual tariffs rather than a price index.

We also compared our findings with the results produced by undertaking a similar analysis using a domestic two rate tariff. This comparison produced similar outcomes in terms of the trend in network costs.

Our findings on annual network charges are also consistent with the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors).

The Victorian results in respect of network costs differ from the results of our analysis for New South Wales (NSW) and Queensland (refer to Section 5). In these States, network costs have been increasing in part due to the substantial capital investments that have been made, particularly in recent years. The different results between States may also reflect the different starting points in respect of each network's existing capital stock.

[9] Assumed to be representative of the general trend in electricity prices in Victoria – see footnote 1.

Glossary

Reference	Description
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CPI	Consumer Price Index
CSO	Community Service Obligation
DUOS	Distribution Use of System
ESC	Essential Services Commission of Victoria
ESAA	Energy Supply Association of Australia
GST	Goods and Services Tax
IPART	Independent Pricing and Regulatory Tribunal
MCE	Ministerial Council on Energy
MWh	Megawatt-hour
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Metering Identifier
NSW	New South Wales
NUOS	Network Use of System
ORG	Office of the Regulator-General, Victoria
QCA	Queensland Competition Authority
QLD	Queensland
TUOS	Transmission Use of System

2. Introduction

2.1 Scope of work

Ernst & Young Australia (Ernst & Young) was jointly engaged by CitiPower Pty, Jemena Electricity Networks (Vic) Ltd, Powercor Australia Ltd, SP AusNet and United Energy Distribution Pty Ltd (collectively referred to herein as "the Victorian electricity network businesses") to assess the trend in Victorian electricity prices and network costs. More specifically, Ernst & Young was engaged to:

- Investigate the options for analysing Victorian electricity prices over the medium term;
- Conduct an independent analysis of the trends in those electricity prices;
- Disaggregate those trends to examine the role of network costs in the changes in Victorian electricity prices; and
- Compare the results with those observed in other Australian jurisdictions to the extent possible.

Section 3 describes the approach undertaken to complete the work.

2.2 Outline of report

This report provides the output of our analysis. In particular:

- Section 3 describes our approach;
- Section 4 provides an overview of our key findings; and
- Section 5 provides an overview of our key findings in NSW and Queensland.

There are two appendices:

- Appendix A – Approach; providing additional details on our methodology, data sources and key assumptions; and
- Appendix B – Other results; providing an overview of other relevant findings.

3. Approach

We have analysed the historical trend of domestic retail electricity prices in Victoria for each year from 1996 to 2010 and have disaggregated the change in prices down to the network and non-network components (i.e. wholesale energy costs and retailers' costs) of retail electricity prices.

Network costs (NUOS) have been disaggregated into distribution use of system costs (DUOS) and transmission use of system costs (TUOS). We have included the cost of the advanced metering infrastructure (AMI) or "smart meters" in the network component.

This allowed us to determine the change in the proportion of the typical customer's annual electricity costs paid to network businesses through network charges, and the change in the proportion that is paid to other non-network entities (e.g. retailers, generators etc).

3.1 Methodology

Analysing electricity prices over long periods of time presents a number of challenges due to changes in industry structure, ownership, information gathering processes and publication, the technology employed, the number and structure of tariffs over time, consumer behaviour and the tax system (e.g. the introduction of the GST and the easement land tax paid by the Victorian transmission business).

For example, there have been numerous structural, regulatory and policy decisions that have significantly impacted the Victorian electricity industry between 1996 and 2010, including

- Privatisation of the five Victorian electricity distribution businesses in 1995-96;
- The introduction of the GST in July 2000[10] and the easement land tax in 2004;
- The implementation of Full Retail Contestability in 2002;
- The previous Victorian Government's decision to roll out AMI to all Victorian residents in 2006; and
- The removal of retail price regulation for small customers in 2007.

Furthermore, significant volumes of historical tariff and metering data are often unavailable, particularly where distribution businesses have merged or where data storage platforms have changed considerably.

To analyse the trend in Victorian electricity prices over the medium term we have relied principally on a bottom up approach as it uses the actual retail and network tariffs paid by customers. Using these tariffs, we have examined the historical trend of annual electricity costs for the typical domestic customer from 1996 to 2010 and have disaggregated the change in the trend down to the network and non-network components of retail electricity prices.[11]

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[10] All prices and costs exclude GST to the extent that all tariff data we have used in our analysis is exclusive of GST. We have not excluded the impact of the introduction of the GST in July 2000 on CPI / inflation data. However we expect that the impact on our final results is unlikely to be material.

[11] 1996 was the first year when prices charged by the Victorian electricity network businesses were separately regulated as part of a broader industry restructure. There are thus significant limitations on data availability prior to this.

As a result, we have assumed the domestic single rate tariff[12] is representative of typical domestic electricity prices, as over 90 per cent of domestic electricity consumers in Victoria pay this tariff.[13]

To undertake this assignment, we took the following broad approach:

- We obtained data on annual retail electricity tariffs in Victoria for domestic customers from the Victorian Government Gazette for each year from 1996 to 2010. Using these tariffs, we estimated the cost of electricity paid each year by a Victorian customer with an average consumption profile[14] under a domestic single rate tariff in this period; and

- We then determined the proportion of the annual electricity costs attributable to the network component, by undertaking the above analysis for the domestic single rate network tariff (i.e. the network tariff charged by the distribution businesses).

We completed this for each of the five Victorian network businesses in turn and then calculated a Victorian average, weighted by the megawatt-hours distributed by each business.

In NSW and Queensland, we were constrained by the unavailability of network tariff data prior to around 2001-02 due to additional data limitations of the type described above.

3.2 Qualifications

The period from 1996 to 2010 was used as the period of analysis as 1996 was the first year when prices charged by the Victorian electricity network businesses were separately regulated. Prior to this, there are significant limitations on the availability of data required to disaggregate electricity prices.

Our findings are first determined in terms of annual cost per customer. We then express the annual cost on a per unit of volume basis (i.e. MWh) by dividing the annual cost per customer by average consumption for that year.[15]

Unless otherwise stated, all findings express our estimates of the annual electricity costs paid by the typical domestic customer, i.e. a customer with an average consumption profile in each year from 1996 to 2010.

We have not analysed the cost of electricity in the non-domestic or business sectors for various reasons, including the limited availability of consistent data, large numbers of non-domestic tariffs, complexity of the non-domestic tariff structures and prevalence of non-standard contracts negotiated individually with the network business.

All the data we have used in our analysis is publicly accessible. To validate our analysis, the Victorian electricity network businesses provided confidential data on customer numbers and average consumption by tariff type and SP AusNet provided data on costs associated with the easement land tax. However this data has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

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[12] A single rate tariff can also be referred to as a 'Domestic General' or 'Peak Anytime' tariff.
[13] Data made available to us suggests that 90% of domestic electricity customers in Victoria are under a single rate tariff based on data on domestic customer numbers by tariff type provided by the Victorian electricity network businesses. While this data is not publicly accessible, we have not used the data in our analysis.
[14] State-wide average consumption data for each year from 1996 to 2010 was sourced from the ESAA's annual Electricity Gas Australia publications.
[15] For example, if the annual cost per customer is $1,000 and consumption for the year is 5,000kWh or 5 MWh, the cost per MWh distributed is $200 per MWh.

3.3 Verification of results

We have only presented the findings from our bottom up analysis of the domestic single rate tariff. We adopted this approach because the single rate tariff is the price that most domestic customers actually pay for electricity.

However we also analysed and disaggregated the trend in electricity prices using other approaches to test the sensitivity and robustness of our findings under the single rate tariff. We have compared the findings derived from the analysis described above:

- With the results of our top down approach, which disaggregates the ABS electricity price index for Melbourne and uses aggregate industry data rather than actual tariffs paid by customers;
- With the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors); and
- With the results derived from similar bottom up analysis described above using a domestic two rate tariff.

Both the bottom up analysis of the two rate tariff and the top down approach produce results which are consistent with the single rate tariff.

Appendix A describes our approach in more detail. Appendix B provides some additional results of our analysis.

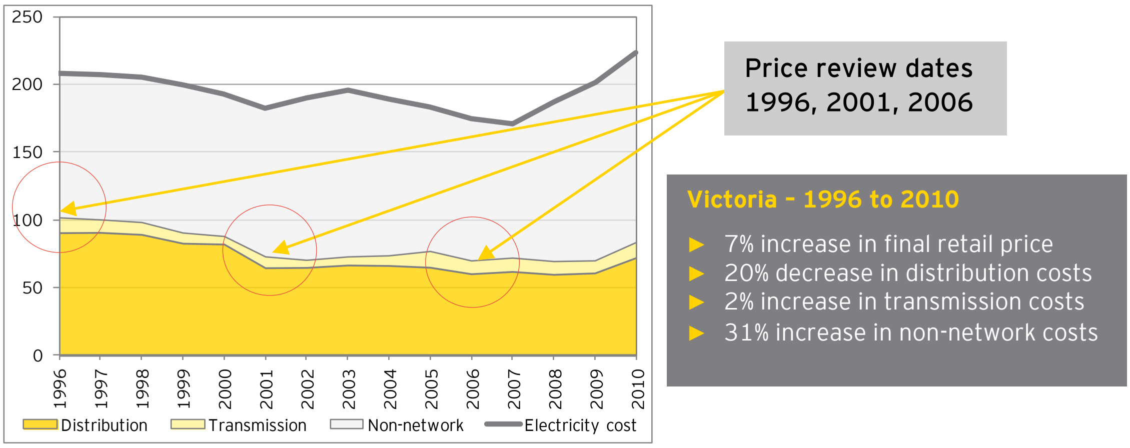
4. Key findings

4.1 Victoria

4.1.1 Costs per MWh

Our findings from the disaggregation of costs under the domestic single rate tariff in Figure 2 show the cost of electricity in real dollars per MWh paid by the typical customer increased by 7 per cent from 1996 to 2010. It also shows relevant price review dates and summarises the impact on the key components of electricity prices.

Figure 2 Victoria electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

In other words, between 1996 and 2010:

- Network costs decreased by 18 per cent in real terms. Disaggregating network costs further shows that:
  - Distribution costs decreased by 20 per cent in real terms, including AMI costs; and
  - Transmission costs increased by 2 per cent in real terms, but have been driven higher by other factors, such as the easement land tax paid by the transmission business in Victoria.[16] If the easement land tax was not paid by the transmission business, transmission costs would have fallen significantly, by as much as 18 per cent in real terms between 1996 and 2010. As shown by Figure 2, transmission costs are also quite volatile for several other reasons also unrelated to the cost of providing transmission services.[17] Our results in respect of transmission costs should therefore be interpreted with particular caution.
- Non-network costs (i.e. wholesale energy and retailers' costs) increased by 31 per cent in real terms.

[16] In Victoria, TUOS charges also include an easement land tax from 2004 onwards, which is the land tax payable by on easements held by electricity transmission companies. This tax is fully passed through to the Government.

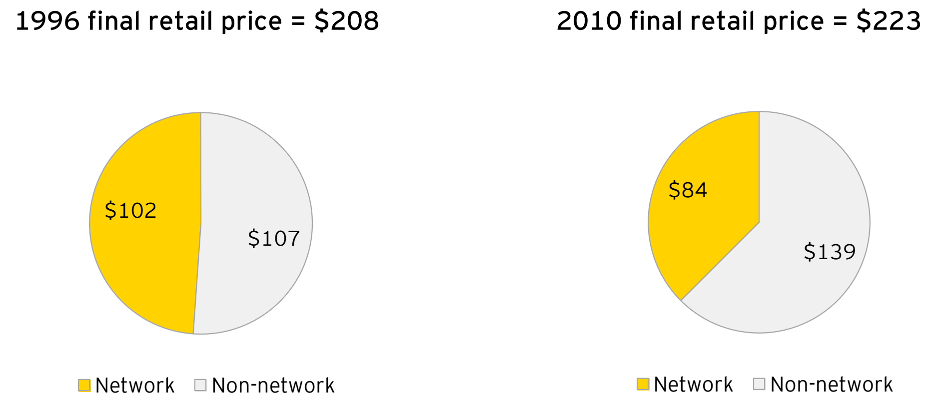
[17] 'Transmission' costs as measured capture some costs that are in practice unrelated to transmission services. These include various electricity market fees, including National Electricity Market (NEM) fees, and settlement residue costs and the costs of the associated auctions. In 2010, these costs were equivalent to about 34% of AEMO's TUOS income. See AEMO, Annual Report 2010, October 2010. NEM fees increased by over 10% between 2009 and 10, and we understand settlement residue costs can be volatile both in terms of both their quantity and incidence (i.e. which jurisdiction bears the costs). Appendix B also shows volatility by distributor.

In 2006, the previous Victorian Government rolled out AMI to all small Victorian electricity customers, which has implications for customers' costs. This can be seen in Figure 2 from the increase in distribution costs particularly from 2009.

In the absence of a roll out of advanced meter infrastructure, we believe the best estimate of network costs would mean the decrease in distribution network costs between 1996 and 2010 would be almost double the estimate of 20 per cent.

Figure 3 shows the breakdown of Victorian electricity costs between network and non-network costs in 1996 and 2010.

Figure 3 Composition of electricity costs in Victoria 1996 and 2010 ($ per MWh, real 2010)

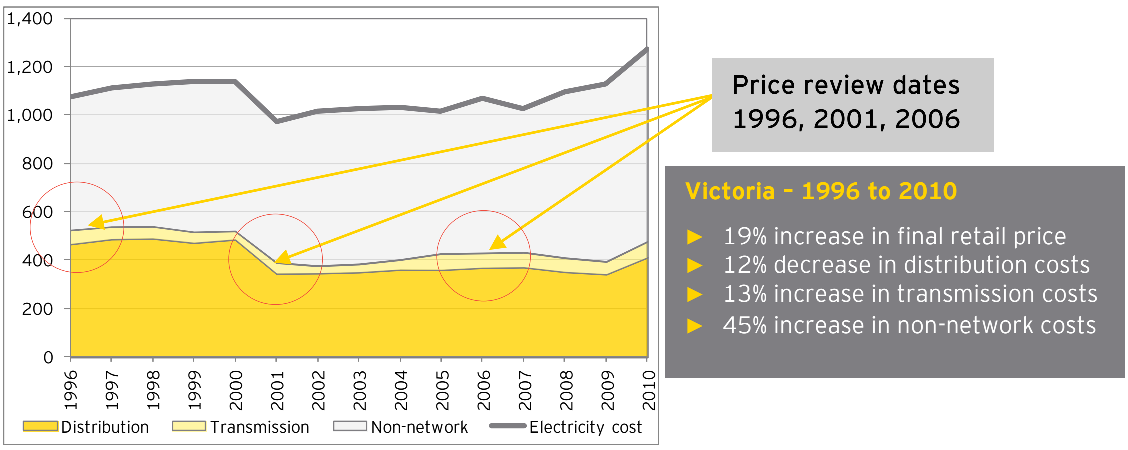


Note: Figures may be affected by rounding. Source: Ernst & Young analysis

4.1.2 Costs per customer

Analysing the breakdown of Victorian electricity costs on a per customer basis, as shown in Figure 4, produces broadly consistent results with our findings on a per MWh basis.

Figure 4 Victoria electricity costs by component 1996 to 2010 ($ per customer, real 2010)



Source: Ernst & Young analysis

Figure 4 shows that between 1996 and 2010:

- The cost of electricity in real dollars per customer paid by the typical customer increased by 19 per cent.
- Network costs decreased by 9 per cent in real terms;
  - Distribution costs decreased by 12 per cent in real terms; and

- Transmission costs increased in real terms by 13 per cent, but as noted above, they have been driven higher by other factors such as the easement land tax. In the absence of the easement land tax paid by the transmission business, transmission costs per customer would have fallen by an estimated 8 per cent in real terms between 1996 and 2010;[18]

- Non-network costs increased by 45 per cent in real terms.

The difference in the magnitude in the change in costs per customer compared with costs per MWh from 1996 to 2010 is explained by the increasing average consumption rates during this period.

4.1.3 Analysis of a typical annual bill in nominal terms

Our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer increased by 69 per cent from $752 to $1,273 between 1996 and 2010.

$752	$1,273	$521
The cost of the typical annual domestic electricity bill in Victoria in 1996	The cost of the typical annual domestic electricity bill in Victoria in 2010	Increase in the typical annual domestic electricity bill in Victoria from 1996 to 2010

Table 2 shows a breakdown of the typical Victorian domestic electricity bill in 1996 and 2010.

Table 2 Breakdown of a typical electricity bill in Victoria ($ per customer, nominal)

	1996	2010
Annual cost of bill ($, nominal)		
Network	$368	$477
Non-network	$385	$796
Final retail price	$752	$1,273
Proportion of final retail price (%)		
Network	49%	38%
Non-network	51%	62%

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Breaking down the bill increase between 1996 and 2010 of $521 in nominal terms, it is evident that:

- Network costs contributed 21 per cent ($110) of the increase in the average electricity bill; and

- Non-network costs contributed 79 per cent ($411) of the increase in the average electricity bill.[19]

4.1.4 Zero load growth for a typical customer

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year for a typical domestic customer in Victoria.

[18] Refer to footnotes 16 and 17 for discussion of the volatility of transmission costs in Victoria.
[19] Figures may be affected by rounding.

We have focused our analysis on the network charges paid by a typical domestic customer as opposed to overall network costs because focussing on the latter is not possible without access to a network business's tariff model due to the complex nature of determining network charges.

Network businesses typically set tariffs based on two factors: the total amount of costs to recover through its network charges and the volume of electricity it distributes:

► Costs – if average consumption was fixed from 1996 to 2010, a network business would not necessarily have invested the same amount to expand or upgrade its network.[20] This would mean that it is likely that the network business would set a lower network charge than otherwise because the total amount of costs to recover would be lower.

► Volume – given price is broadly a function of costs and volume, if a network business distributes less electricity than expected (for example, if growth in average consumption is zero), it would most likely set a higher network charge to ensure it recovers its costs.

Typically for networks, it would be reasonable to expect increasing volumes to increase total costs but result in declining per unit costs.

Whether network charges would be higher or lower under a zero load growth scenario would depend on which of these two opposing impacts (lower costs to recover versus lower volumes from which to recover costs) is stronger. The results should therefore be interpreted with some caution.

Table 3 compares the distribution costs paid by a typical customer in 1996 and 2010 with the distribution costs the same customer would pay if his or her consumption remained at 1996 levels.

Table 3 Annual distribution costs of a typical customer in Victoria ($ per customer, real 2010)

	1996	2010	Change 1996-2010 ($)
Typical customer	$466	$412	-$54
Zero load growth	$466	$375	-$91

Source: Ernst & Young analysis

In terms of annual network costs, the typical customer in Victoria is better off by $54 between 1996 and 2010.

A typical customer whose consumption remained at 1996 levels would be a further $37 better off. This customer would be better off by $91 between 1996 and 2010.

The implication of this analysis is that performance improvements in the Victorian distribution network have likely played a significant role. Table 3 suggests Victorian domestic electricity customers have received benefits in addition to those benefits that one might reasonably expect to arise from increasing volumes (i.e. benefits from increasing total costs but declining per unit costs).

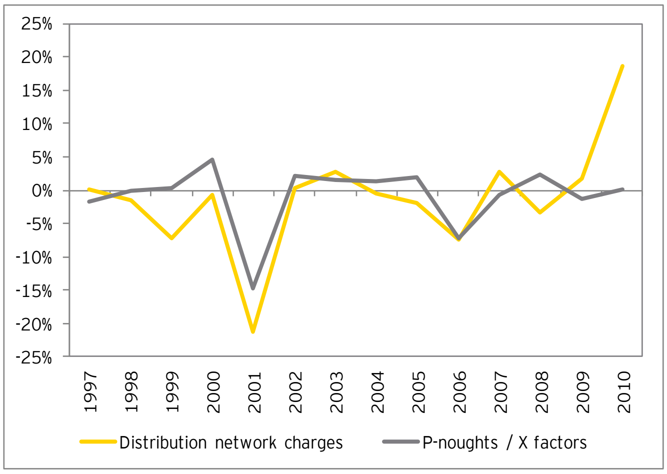
In other words, total network costs for Victorian domestic electricity customers have fallen despite increasing volumes.

4.1.5 Comparison with regulatory determinations

We have also cross-checked our findings by comparing the trend in network costs in Victoria between 1996 and 2010 with the P-noughts and X factors for the distributors' network businesses, allowed in regulatory determinations for this period. It is apparent from Figure 5 that there is a high degree of consistency between the two trend lines.

[20] The key relationship for cost is with the disaggregated growth in peak demand,

Figure 5 Victoria annual changes in electricity distribution network prices 1996 to 2010 (%)



Source: Ernst & Young analysis, AER, ESC, ORG

4.1.6 Victorian summary

Our analysis shows that for Victorian domestic electricity customers:

- Network costs have not been the driver of the increase in retail electricity prices for domestic customers between 1996 and 2010;
    - Distribution network costs have decreased by 20 per cent in real terms between 1996 and 2010, including AMI costs;
    - Transmission network costs have increased slightly by 2 per cent in real terms during this period, but are driven higher by other factors, such as the easement land tax paid by the transmission business in Victoria;
- In contrast, non-network costs (i.e. wholesale energy costs and retailers' costs) have increased by 31 per cent between 1996 and 2010.

These results are supported by the findings of all of the additional analysis we undertook, that is:

- Analysing the typical annual bill for the typical customer;
- Disaggregating electricity prices using the top down approach;
- Performing the equivalent analysis to disaggregate the domestic two rate tariff; and
- Comparing the findings on annual network charges against the P-noughts and X factors allowed in regulatory determinations made for the distributors' network businesses.

5. Other jurisdictions – New South Wales and Queensland

We have applied a similar approach to analyse the historical trend in domestic retail electricity costs and the disaggregation between the network and non-network components in NSW and Queensland.[21]

There were three key differences in our analysis of NSW and Queensland electricity prices:

- Prior to around 2001-02, we were constrained by the unavailability of network tariff data. To overcome this, we interpolated the network tariff data back to 1996 using the "P-noughts" and "X factors" allowed in each year of the regulatory period in determinations made by the economic regulator;

- Unlike in Victoria, the annual prices submitted to the regulator by NSW and Queensland distribution businesses do not disaggregate network prices into distribution (i.e. DUOS) and transmission (i.e. TUOS) prices. We were therefore unable to disaggregate network tariffs; and

- We adjusted for a distortion in Queensland retail electricity prices caused by the Uniform Tariff Policy. Refer to Section A.1.1 for more detail.

Our analysis shows that the increases in annual domestic electricity prices in NSW and Queensland paid by the typical customer between 1996-97 and 2010-11[22] are explained by increases in network costs.

Between 1996-97 and 2010-11, network costs paid by the typical customer in NSW and Queensland have increased in real terms by 65 per cent and 105 per cent respectively. Table 4 shows the results.

Table 4 Change in average annual electricity costs from 1996-97 to 2010-11 ($ per MWh, real 2010)

	Percentage change		Dollar change	
	New South Wales	Queensland	New South Wales	Queensland
Final retail price	+45%	+46%	+$67	+$65
Network	+65%	+105%	+$44	+$55
Non-network	+28%	+11%	+$22	+$10

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Several interested parties have cited the key drivers of increasing network costs (and hence electricity prices) in NSW and Queensland to include rising peak demand and the need to replace ageing and obsolete assets. These parties include AusGrid,[23] the Australian Energy Regulator (AER),[24] the Australian Industry Group[25] and the Reserve Bank of Australia.[26]

We present the following findings from our analysis of electricity prices in NSW and Queensland:

[21] We analysed NSW and Queensland as we believe they are the most relevant States to compare with Victoria.
[22] Electricity prices in NSW and Queensland were analysed on a financial year basis (as opposed to a calendar year basis as in Victoria) as it is consistent with the regulatory years over which electricity prices and regulated revenues are determined under the regulatory regime in NSW and Queensland.
[23] George Maltabarow, Managing Director of AusGrid, Appearance on Insight episode 'Power Play', 2 August 2011, transcript available at http://www.sbs.com.au/insight/episode/index/id/419/Power-Play#transcript
[24] AER, State of the energy market 2010, page 4
[25] Australian Industry Group, Energy shock: confronting higher prices, February 2011, page 21
[26] Reserve Bank of Australia, Developments in Utilities – Bulletin December Quarter 2010, available at http://www.rba.gov.au/publications/bulletin/2010/dec/2.html

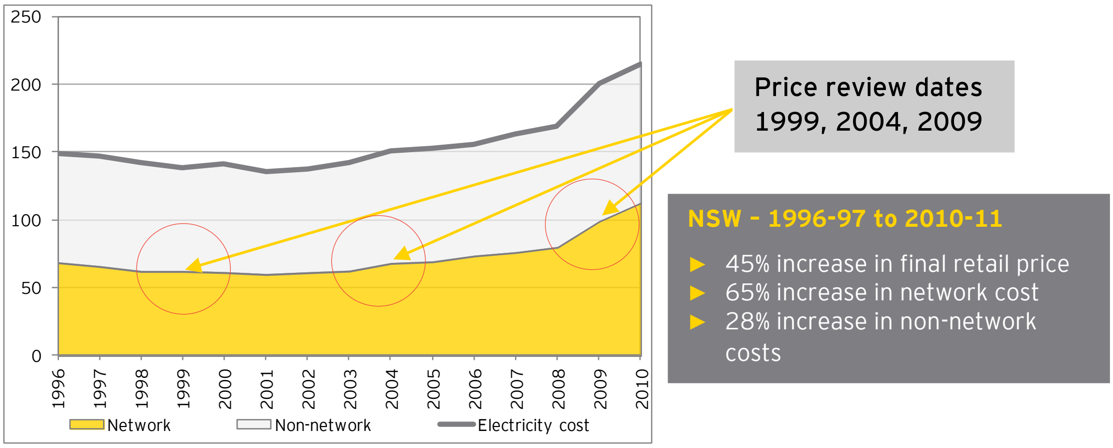
- Disaggregation of costs under the domestic single rate tariff on a per MWh basis;
- Typical annual bill;
- Comparing the change in network costs with price changes allowed in regulatory determinations; and
- Zero load growth for a typical customer (refer to Section B.3).

Our analysis shows that the change in annual network costs between 1996-97 and 2010-11 in NSW and Queensland are more significant than in Victoria.

5.1.1 Costs per MWh

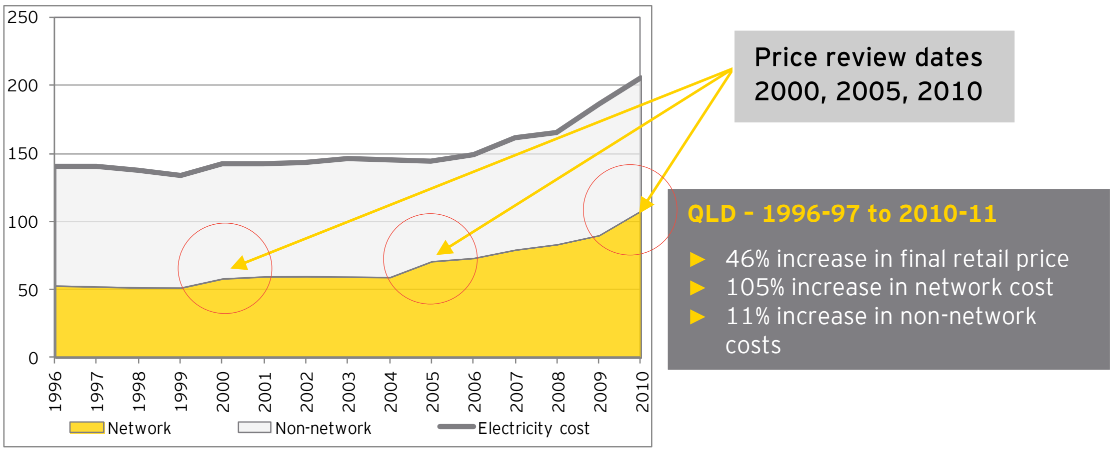
Figure 6 and Figure 7 show the disaggregation of costs under the domestic single rate tariff for NSW and Queensland. Costs are in real dollars per megawatt-hour (MWh) paid by the typical customer from 1996-97 to 2010-11. It also shows relevant price review dates and summarises the impact on the key components of electricity prices.

Figure 6 New South Wales electricity costs by component 1996-97 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

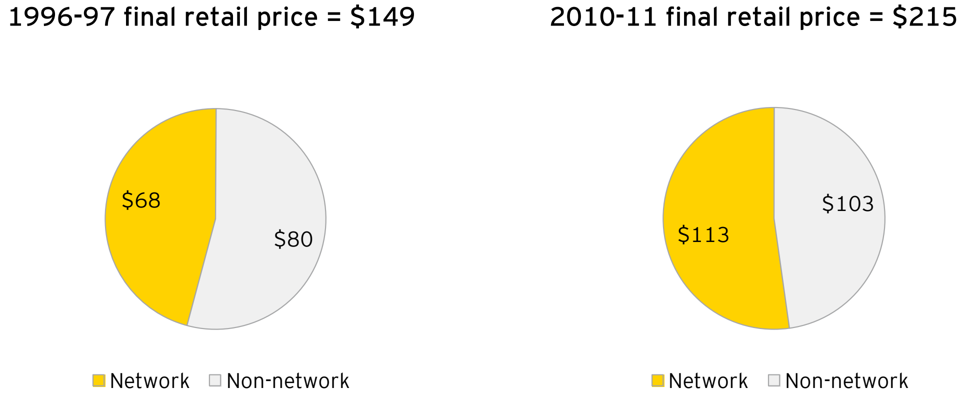
Figure 7 Queensland electricity costs by component 1996-97 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

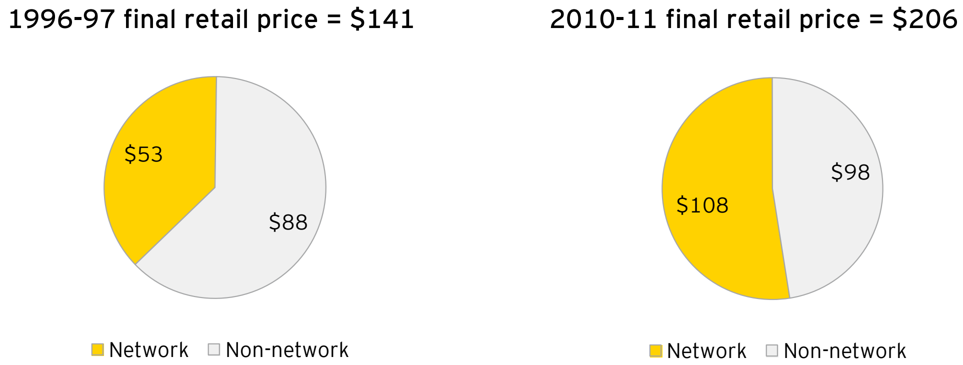
Figure 8 and Figure 9 show the breakdown of electricity costs between network and non-network costs in 1996-97 and 2010-11 for NSW and Queensland.

Figure 8 Composition of electricity costs in NSW 1996-97 and 2010-11 ($ per MWh, real 2010)



Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Figure 9 Composition of electricity costs in Queensland 1996-97 and 2010-11 ($ per MWh, real 2010)



Note: Figures may be affected by rounding. Source: Ernst & Young analysis

5.1.2 Analysis of a typical average bill in nominal terms

For NSW, our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer[27] increased by 109 per cent from $720 to $1,503 between 1996-97 and 2010-11.

$720	$1,503	$783
The cost of the average annual domestic electricity bill in NSW in 1996-97	The cost of the average annual domestic electricity bill in NSW in 2010-11	Increase in the average annual electricity bill in NSW from 1996-97 to 2010-11

Table 5 Breakdown of a typical electricity bill in NSW ($ per customer, nominal)

	1996-97	2010-11
Annual cost of bill ($, nominal)		
Network	$331	$785
Non-network	$389	$718
Final retail price	$720	$1,503
Proportion of final retail price (%)		
Network	46%	52%
Non-network	54%	48%

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

[27] Typical customer with an average consumption profile from 1996 to 2010

For Queensland, our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer[28] increased by 162 per cent from $615 to $1,608 between 1996-97 and 2010-11.

$615	$1,608	$993
The cost of the average annual domestic electricity bill in QLD in 1996-97	The cost of the average annual domestic electricity bill in QLD in 2010-11	Increase in the average annual electricity bill in QLD from 1996-97 to 2010-11

Table 6 Breakdown of a typical electricity bill in Queensland ($ per customer, nominal)

	1996-97	2010-11
Annual cost of bill ($, nominal)		
Network	$230	$844
Non-network	$385	$764
Final retail price	$615	$1,608
Proportion of final retail price (%)		
Network	37%	52%
Non-network	63%	48%

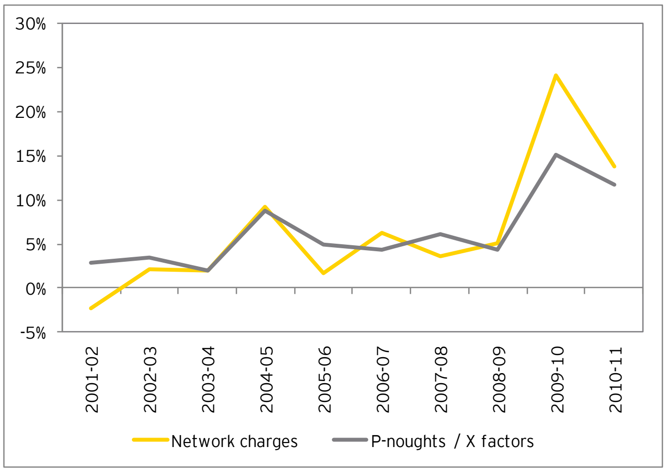
Note: Figures may be affected by rounding. Source: Ernst & Young analysis

5.1.3 Comparison with regulatory determinations

In NSW and Queensland, we performed the same cross-checks as in Victoria by comparing the trend in network costs with the annual price changes allowed by economic regulators in each year of the regulatory period in determinations made for the distributors' network businesses (i.e. P-noughts and X factors).[29]

These cross-checks for NSW and Queensland produced consistent results as the cross-checks for Victoria, suggesting reasonable consistency in the trend between network costs paid by a typical domestic customer and a distributor's P-noughts and X factors between 2001-02 and 2010-11.[30]

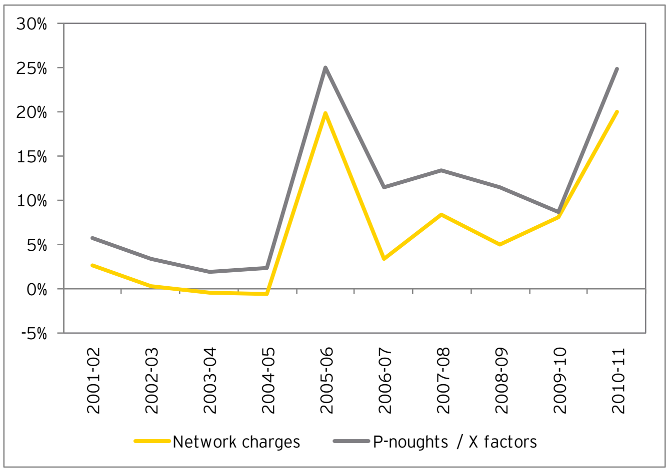
Figure 10 New South Wales annual changes in electricity network costs 2001-02 to 2010-11 (%)



Source: Ernst & Young analysis, AER, IPART

[28] Typical customer with an average consumption profile from 1996 to 2010
[29] Note that P-noughts and X factors for NSW and Queensland businesses are for distribution use of system prices only and do not include transmission use of system prices. These were sourced from distribution determinations made by the IPART, QCA and AER. See Appendix B for details.
[30] In NSW and Queensland, we have compared network charges and P-noughts / X factors from 2001-02 as were constrained by the unavailability of network tariff data in these States prior to this date.

Figure 11 Queensland annual changes in electricity network costs 2001-02 to 2010-11 (%)



Source: Ernst & Young analysis, AER, QCA

We have also undertaken an analysis of zero load growth scenarios in NSW and Queensland. These findings are presented in Appendix B.

Appendices to report

Appendix A: Approach

A.1. Methodology

The objective of our analysis is to:

- Determine the changes in domestic retail electricity prices in Victoria between 1996 and 2010; and

- Determine the changes in the components that make up the domestic retail electricity prices, having specific regard for the network component, the AMI (or advanced metering) component and the non-network component. The non-network component includes retailers' costs and wholesale energy charges and has been calculated as follows:

Non-network = Final retail price – Network – Advanced metering

We have undertaken two approaches to test the consistency and validity of our analysis: a bottom up and a top down approach. The bottom up approach involves disaggregating annual electricity costs based on actual tariffs and has been undertaken using the domestic single rate and domestic two rate tariffs. The top down approach involves disaggregating annual electricity costs based on the ABS's electricity price index.

These approaches, and our approach to replicating the analysis in NSW and Queensland, are described in more detail below.

A.1.1. Bottom up approach

This approach involves using the individual retail and network domestic single rate tariffs for each distribution business to estimate annual electricity costs based on average consumption profiles (i.e. a customer consuming the average level of domestic consumption in each year from 1996 to 2010). The annual electricity costs are then aggregated for the five distribution business to give a whole of Victoria annual electricity cost.

We have undertaken this analysis with both the domestic single rate tariff and the domestic two rate tariffs to test the sensitivity and robustness of our findings.

The steps involved in the bottom up approach for a customer in each distribution zone are set out below (using the single rate tariff analysis as an example):

1. Using the retailer's annual standing offer (i.e. default) domestic single rate tariff, determine the annual retail electricity cost for each year from 1996 to 2010 paid to the retailer by a domestic customer consuming the average amount of electricity each year. The average amount of electricity represents the average consumption of a customer in Victoria for each year.

2. Using the domestic single rate network tariff for the distribution zone, determine the annual network cost component for each year from 1996 to 2010 attributable to a domestic customer consuming the average amount of electricity each year.

3. For Victorian customers only, determine the annual costs paid by a domestic consumer for AMI for each year from 2006 to 2010. For domestic consumers under a domestic single rate tariff, the meter is assumed to be a single phase non off-peak meter that is read quarterly. These charges are currently prescribed by the AER and prior to 2010, by the Essential Services Commission of Victoria (ESC).

4. The non-network cost attributable to a customer consuming the average amount of electricity for each year is calculated as the difference between the annual retail electricity cost and the sum of the network and AMI costs.

5. Having determined the annual retail electricity costs paid by the average domestic consumer and the corresponding cost components in each distribution zone, State-wide annual electricity costs are calculated using a weighted average based on the volume of megawatt-hours of electricity distributed in each distribution zone.

New South Wales

In NSW, we were constrained by the unavailability of network tariff data before 2001-02 due to reasons such as the changing number and structure of tariffs over time, distribution businesses having merged, and significant changes in data storage platforms.

For these years, we consequently interpolated the network tariffs based on average annual price movements allowed by the regulator for the relevant year, using the approved P-nought and X factor adjustments. Refer to the Section on Key assumptions for more detail.

Queensland

As with NSW data, we were also constrained by the unavailability of network tariff data from network businesses in Queensland prior to around 2002. We consequently interpolated network tariffs for missing years based on approved P-nought and X factors adjustments or, where these were not available, changes in CPI.

In addition, our analysis in Queensland is complicated by the Uniform Tariff Policy, which ensures that all customers in Queensland pay no more than regulated prices available to customers in southeast Queensland. This means that the Queensland Government provides a Community Service Obligation (CSO) payment to subsidise the cost of electricity in regional Queensland.[31] The Queensland Government provided CSO payments of approximately $250 million to the electricity retailer in regional Queensland in 2009-10.[32]

This creates a distortion in the disaggregation of electricity costs in Queensland because retail electricity prices in regional Queensland are not fully reflective of the true network costs. The Uniform Tariff Policy requires a retailer in regional Queensland to set the same price for electricity as a retailer in southeast Queensland, despite the difference in network costs incurred in delivering electricity in these two areas.

This creates issues when it comes to disaggregating the change in domestic retail electricity prices in Queensland down to the network and non-network components, for example:

- The annual retail electricity costs produced by our analysis are lower than the fully cost-reflective prices;
- The network component is cost-reflective;
- As the non-network component of electricity prices is estimated as the difference between the retail price and the network component, the non-network component appears lower than it would be if retail prices were cost-reflective; and
- In practice, the distortion is corrected by the CSO payment which ensures that the incumbent retailer in regional Queensland recovers its network costs, while charging a retail price to its domestic customers which is lower than cost-reflective levels.

To correct this distortion, we have scaled down the network cost component in Queensland.

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[31] http://www.ergon.com.au/your-home/accounts--and--billing/electricity-prices
[32] http://www.dme.qld.gov.au/zone_files/Electricity/ergon_energy's_role_in_a_competitive_queensland_electricity_market.pdf

Based on our other work in the electricity sector, we understand that the network component typically comprises between 45 per cent and 55 per cent of retail electricity costs in Queensland. This understanding is consistent with the findings of the QCA, which estimated that network costs account for 47% of the total cost of supplying electricity in 2009-10.[33]

We have thus normalised our estimate of the network cost component in Queensland, setting annual network costs to account for 50 per cent of the annual retail electricity price in 2010-11. We then extrapolated the normalised network cost in 2010-11 back to 1996-97 using the actual observed trend in network costs.

As a result, all charts on Queensland in this report reflects the trend in network costs over time, rather than the actual dollar value and the dollar values should be interpreted with some caution.

A.1.2. Zero load growth for typical customer scenario

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year. To do this, we would have to determine what network charges would be if average consumption remained fixed from 1996 to 2010.

However without access to a network business's tariff model, this is not possible due to the complex nature of determining network charges.

Network businesses typically set tariffs based on two factors: the total amount of costs to recover through its network charges and the volume of electricity it distributes.

- Costs – if average consumption was fixed from 1996 to 2010, a network business would not necessarily have invested the same amount to expand or upgrade its network. This would mean that it is likely that the network business would set a lower network charge than otherwise because the total amount of costs to recover would be lower.

- Volume – given price is broadly a function of costs and volume, if a network business distributes less electricity than expected (for example, if growth in average consumption is zero), it would most likely set a higher network charge to ensure it recovers its costs.

Whether network charges would be higher or lower than otherwise would depend on which of these two opposing impacts (lower costs to recover versus lower volumes from which to recover costs) is stronger. This would require considering whether network investment in capital projects would have taken place based on the lower consumption profile which would be a complex process which we could not undertake with any certainty.

As a result, we have simplified the analysis to focus on the annual electricity costs paid by the typical customer from 1996 to 2010 if he or she fixed consumption at 1996 levels, holding all retail and network charges constant.

That is, this reflects the impact of load growth on one customer, rather than the impact on the annual cost of the network component of electricity.

The results should therefore be interpreted with some caution.

[33] Queensland Competition Authority, Final Decision on 2009-10 Benchmark Retail Cost Index, June 2009, page 5.

A.1.3. Top down approach

This approach relies on the ABS electricity price index to estimate average annual retail electricity costs for domestic customers, and only requires the aggregation of electricity costs from individual tariffs for one year.

The top down approach consists of the following steps:

1. Using the retailer's 2010 standing offer (i.e. default) domestic single rate tariff, determine the annual retail electricity cost paid to the retailer each year by a domestic customer consuming the average amount of electricity in 2010.

2. Extrapolate the annual retail electricity cost in 2010 back to 1996 in accordance with the ABS electricity price index to estimate average annual retail electricity costs for domestic customers consuming the average amount of electricity for each year from 1996 and 2009.

3. Estimate the annual network cost component attributable to customers consuming the average amount of electricity for each year from 1996 to 2010 by using the revenue per domestic customer as a proxy for the average annual price of electricity paid by a domestic customer. The revenue per domestic customer is the weighted average revenue per domestic customer based on the volume of megawatt-hours of electricity distributed in each distribution zone.

4. Annual costs for AMI are determined in an identical manner as under the bottom up approach.

5. The non-network cost attributable to a customer consuming the average amount of electricity for each year is calculated in an identical manner as under the bottom up approach.

We have elected to use the results of our down approach as a cross check on the results of our bottom up approach. We have done this for a number of reasons:

- The ABS electricity price index is a well-known and relied upon measure of retail electricity prices in Australia over time;

- There is a degree of uncertainty about how the ABS's price index is precisely calculated (e.g. which types of customers it applies to, does it include customers on market offers and default offers); and

- It is not as precise as the bottom up approach which involves using actual retail tariffs.

Nevertheless, we have undertaken a top down analysis to disaggregate annual electricity costs in Victoria, NSW and Queensland as a check of the robustness and sensitivity of our main findings.[34]

A.2. Data sources

All the data we have used in our analysis is publicly accessible. The Victorian electricity network businesses provided us with confidential data on consumption by tariff type to validate our analysis, but it has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

Table 7 shows the key data sources we used in our analysis.

[34] In all three States, the results of the top down analysis are consistent with our findings from the disaggregation of costs under the domestic single rate tariff.

Table 7 Data sources by State

	Victoria	New South Wales	Queensland
Retail standing offer tariff data	Victorian Government Gazette	Retail businesses (on request)	QLD Government Gazette
Network charge tariff data	Network businesses (on request)	Network businesses (on request)	Network businesses (on request)
Average consumption data (per customer)	ESAA	ESAA	ESAA
Per unit revenue indicators (e.g. revenue per customer, revenue per MWh)	AER / ESC annual performance reports	N/A[35]	N/A[36]
AMI costs	AER / ESC decisions	N/A	N/A
Electricity price index	ABS	ABS	ABS
Inflation data	ABS	ABS	ABS

Note: ABS = Australian Bureau of Statistics; AER = Australian Energy Regulator; ESAA = Energy Supply Association of Australia; ESC = Essential Services Commission of Victoria

A.3. Key assumptions

- Network charges refer to NUOS tariffs, which include both DUOS and TUOS tariffs.
- Unless otherwise stated, all prices and costs exclude GST to allow an appropriate comparison of prices and costs over time from 1996 to 2010.
- AMI costs only apply to Victoria in this report. AMI costs are generally not applicable in NSW and Queensland and have not been included in our analysis for these States as there is no Government-mandate for a small customer roll out of advanced meters at this stage.
- For simplicity, we assumed that the annual per unit metering service charges (for AMI) prescribed by the regulator[37] represents the average AMI costs paid by a domestic consumer each year.
    - In Victoria, the regulator prescribes metering service tariffs to cover meter provision and metering data services, which are either priced on a "per meter" or a "per NMI"[38] basis, depending on the distribution business.
    - Neither the number of meters nor the number of NMIs in the Victorian domestic sector is necessarily representative of the actual number of domestic customers in Victoria. This is because:
        - Domestic dwellings may have more than one meter for each NMI, such as domestic customers who have a dedicated hot water circuit meter in addition to an anytime energy meter. This customer would pay an annual metering service tariff either once (if they are charged per NMI) or twice (if they are charged per meter). For example, Powercor's metering service tariffs are charged per NMI, whereas SP AusNet's metering service tariffs are charged on a per meter basis; and

[35] The AER (and prior to 2008, IPART and the QCA) do not publish annual performance reports containing per unit revenue indicators for electricity distribution network businesses in NSW and Queensland for the 1996-2010 period.
[36] As above
[37] The AER assumed responsibility for the determination of metering services charges for the Victorian electricity network businesses from 2010. From 2006 to 2009, this was the responsibility of the ESC.
[38] A "NMI" is a National Metering Identifier is a unique reference number which defines a set of parameters and information about a particular meter point. The NMI system is implemented across the National Electricity Market.

- In some instances, domestic customers in multi-dwelling complexes (such as high rise apartments, social housing or student accommodation) may not have individual meters and hence would also not have individual NMIs. In these instances, a single NMI assigned to the entire complex.

- The process to obtain the data to aggregate information on an individual NMI and individual meter basis in each distribution zone in Victoria is complex and constrained by data availability. As a result, for simplicity, our analysis assumes that the metering service tariff (whether on a per NMI or per meter basis) prescribed by the regulator will be, on average across the State, broadly equivalent to the annual costs paid by the average domestic consumer.

- In this report, prices and consumption volumes are expressed on a calendar year basis in Victoria, and on a financial year basis in NSW and Queensland. This is consistent with the regulatory years (i.e. twelve-month periods) over which electricity prices and regulated revenues are determined under the regulatory regime in each of these States. Where data is expressed on a partial year basis, we have converted the data on a pro rata basis to calendar year (Victoria) or financial year (NSW and Queensland) terms.

- In some years, annual data on historical network tariffs were not available due to factors such as the merging of distribution businesses or significant changes in data storage platforms.[39] In these instances, we interpolated the tariffs based on average annual price movements allowed by the regulator for the relevant year, using the approved "P-nought" adjustments and "X factors"[40] and taking into account changes in CPI.[41] The P-noughts and X factors for each regulatory period are available from distribution determinations publicly available from the website of the relevant regulator.

- While we recognise that under a weighted average price cap form of price control, P-nought and X factor adjustments refer to the real percentage change allowed in the *weighted average* of a network business's entire suite of tariffs (rather than any individual tariff), and under a revenue cap these represent the real percentage change allowed in the annual revenue requirement, we consider that on balance, it is often likely to be a reasonable proxy for the percentage change in domestic tariffs. See Appendix B for detail of the P-noughts and X factors allowed by the regulator in previous determinations.

- Where a network business formed after 1996, network prices and X factors for each year from 1996 to the year of the entity's formation have been estimated as the average of the prices and X factors of the preceding businesses, typically weighted by the value of the capital base. In this report, we have used this approach for Country Energy prior to its formation in 2001 and for Ergon Energy prior to its formation in 1999.

- Figures presented in this report may be affected by rounding.

[39] The following tariff data was not available: CitiPower tariffs 1996-2000, Powercor tariffs 1996-1998, EnergyAustralia tariffs 1996-97 to 2001-02, Integral Energy tariffs 1996-97 to 2000-01, Country Energy tariffs 1996-97 to 2000-01, Energex tariffs 1996-97 to 2001-02 and Ergon Energy tariffs 1996-97 to 2002-03.

[40] A "P-nought adjustment" is the term given to the percentage increase or decrease in the weighted average of an electricity network business's annual tariffs allowed by the regulator in the first year of a regulatory period. "X factors" are the percentage increase or decrease allowed in all subsequent years of a regulatory period (from the second to the fifth year).

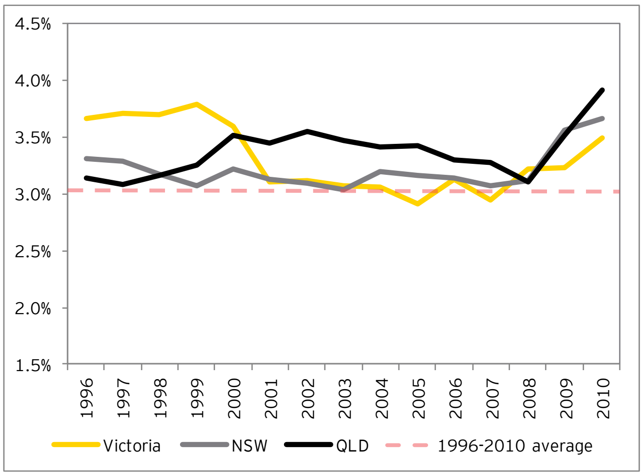
[41] Escalation of prices under *CPI–X* regulation, where a positive value for X indicates a real price decrease under the *CPI–X* formula.

Appendix B: Other results

B.1. Typical annual bill

Figure 12 shows the average annual electricity bill as a proportion of disposable income[42] in Victoria, NSW and Queensland from 1996 to 2010.

Figure 12 Average annual electricity bill as a proportion of disposable income 1996 to 2010 (nominal)



Note: Victorian results on calendar year basis (beginning 1 Jan), results for NSW / QLD on the year beginning 1 July.
Source: Ernst & Young analysis, ABS, ATO.

The proportion of disposable income spent by the typical domestic customer on electricity each year has increased in all three States in recent years. In Victoria, the proportion spent by typical domestic customers is somewhat lower than those in NSW and Queensland. In Victoria, it remains lower than it was in 1996.

However this only addresses the domestic customer with an average consumption profile. If this customer increased consumption by 10 per cent in 2010, the annual electricity bill would increase by:

- 4.3 per cent ($48) in Victoria;
- 8.7 per cent ($131) in NSW; and
- 8.0 per cent ($129) in Queensland.

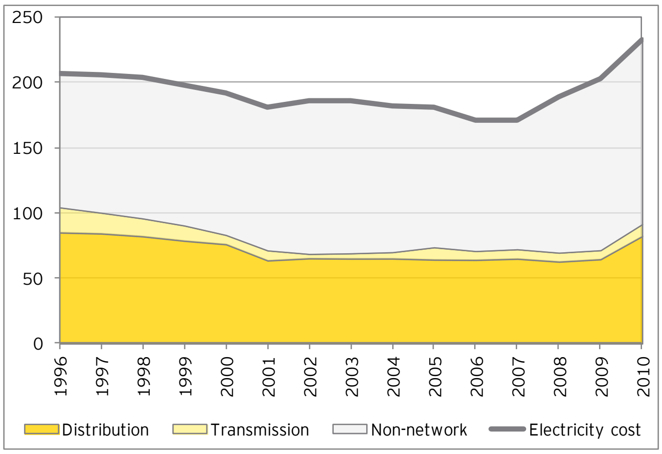
[42] Disposable income is calculated as income measured by the ABS average full time total earnings less tax payable in accordance with the ATO's individual income tax rates from 1996-97 to 2010-11.

B.2. Results by Victorian distributor

This section presents our findings of the disaggregation of electricity prices by distribution network business on a per MWh basis.

Jemena Electricity Networks (JEN)

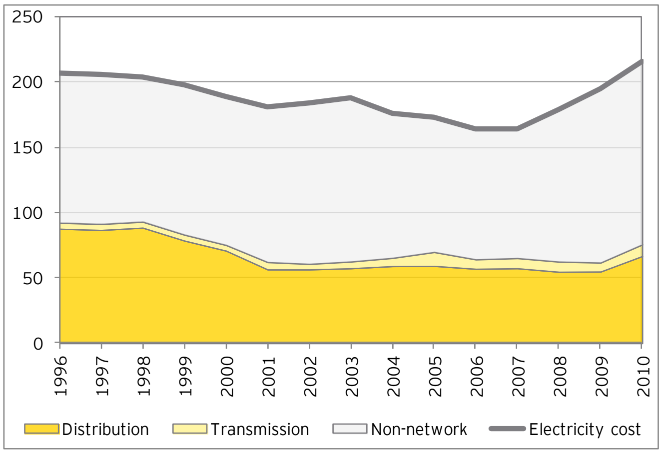
Figure 13 JEN electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

CitiPower

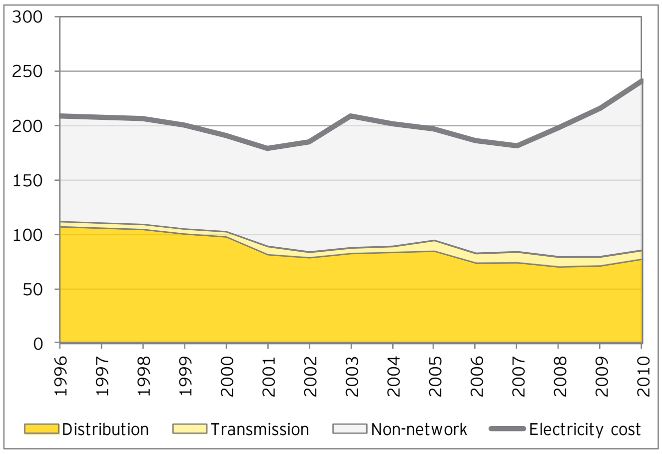
Figure 14 CitiPower electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

Powercor

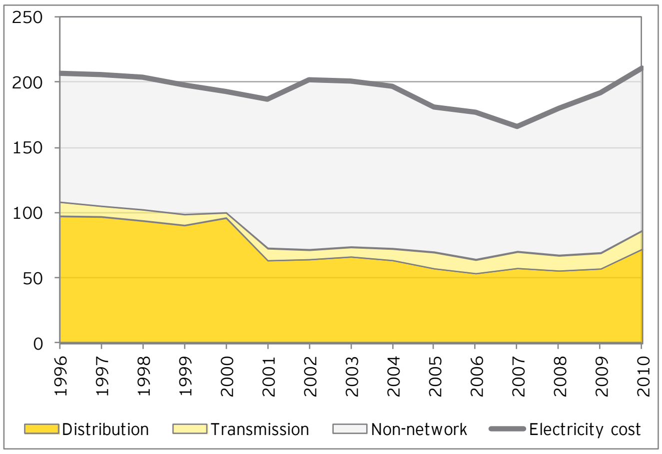
Figure 15 Powercor electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

SP AusNet

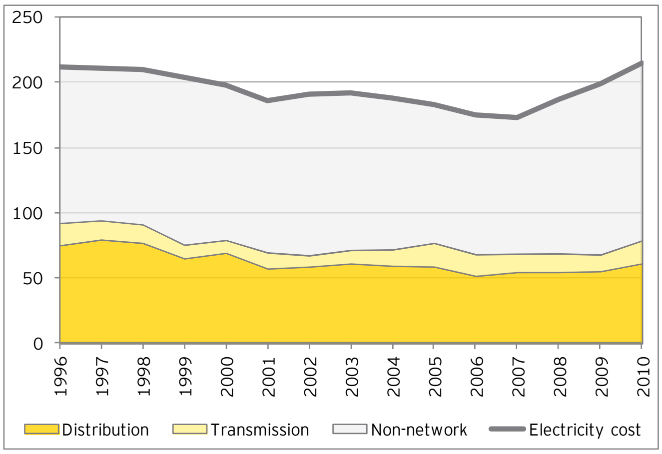
Figure 16 SP AusNet electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

United Energy

Figure 17 United Energy electricity costs by component 1996 to 2010 ($ per MWh, real 2010)



Source: Ernst & Young analysis

The charts in Appendix B show that the volatility in TUOS appears to be exacerbated at the individual distributor level. This is likely to reflect the distributor's decisions in respect of tariff rebalancing between customer classes (i.e. any changes in who they recover these costs from), as our analysis is tariff-specific.

B.3. Zero load growth

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year for the average domestic customer in NSW and Queensland. We have adopted a similar approach to our analysis of the zero load growth scenario in Victoria. Our findings are presented below.

Table 8 Annual distribution costs of a typical customer in NSW ($ per customer, real 2010)

	1996	2010	Change 1996-2010 ($)
Typical customer	$477	$785	+$308
Zero load growth	$477	$748	+$270

Note: Figures may be impacted by rounding. Source: Ernst & Young analysis

Table 9 Annual distribution costs of a typical customer in Queensland ($ per customer, real 2010)

	1996	2010	Change 1996-2010 ($)
Typical customer	$333	$844	+$511
Zero load growth	$333	$709	+$376

Note: Figures may be impacted by rounding. Source: Ernst & Young analysis

The results suggest that even holding consumption constant between 1996 and 2010, the annual network bill of typical domestic customers in NSW and Queensland still increases significantly.

An important point to note is that investment in the augmentation of a distribution network is driven by peak demand growth, not energy demand growth. It is therefore likely that growth in total energy demand may be flat or indeed falling, but if peak demand is growing then this will drive the need for investment in network capacity.

This point has been supported by stakeholders such as the Australian Energy Market Commission (AEMC)[43] and AusGrid.[44] In particular, the AEMC stated that peak demand has grown by 3.5 per cent per annum since 2005, compared to energy demand growth of 1.2 per cent per annum. Meanwhile according to Energex,[45] since 2001-02, peak demand growth has been approximately double the rate of growth in energy volumes.

The zero load growth analysis above (i.e. zero growth in energy demand) does not take into account changes in peak demand. As a result, the results should be interpreted with caution.

B.4. Regulatory decisions

The tables below show the P-noughts and X factors allowed by the regulator to the distribution network businesses in Victoria, NSW and Queensland from 1996 to 2010.

Table 10 Real allowed P-noughts and X factors by distributor in Victoria 1996 to 2015 (%)

	JEN	CitiPower	Powercor	SP AusNet	United Energy	Regulatory Period
1996*	1.50	1.50	1.00	1.00	1.92	1996 to 2000: Victorian Tariff Order
1997*	1.50	1.50	1.00	1.00	1.92	
1998*	1.50	1.50	1.00	1.00	1.92	
1999*	1.50	1.50	1.00	1.00	1.92	

[43] AEMC, Strategic Priorities for Energy Market Development Discussion Paper, 2011, page 4
[44] AusGrid, Response to the AEMC review of strategic priorities for Energy Market Development, May 2011, page 3
[45] Energex, Presentation to the Clean Energy Council Energy Efficiency Seminar, June 2009, slide 5, available online at: http://www.cleanenergycouncil.org.au/cec/mediaevents/Past-Events/EE-presentations/mainColumnParagraphs/0/text_files/file3/TERRY%20MCCONNELL.pdf

2000*	1.50	1.50	1.00	1.00	1.92	
2001*	17.10	12.40	19.60	21.80	12.90	2001 to 2005: ORG price review
2002*	1.00	1.00	1.00	1.00	1.00	
2003*	1.00	1.00	1.00	1.00	1.00	
2004*	1.00	1.00	1.00	1.00	1.00	
2005*	1.00	1.00	1.00	1.00	1.00	
2006*	3.80	8.70	17.30	9.30	14.70	2006 to 2010: ESC price review
2007*	2.50	2.50	2.50	2.50	2.50	
2008*	2.50	2.50	2.50	2.50	2.50	
2009*	2.50	2.50	2.50	2.50	2.50	
2010*	2.50	2.50	2.50	2.50	2.50	
2011	-4.99	6.41	-0.11	-9.99	-0.37	20111 to 2015: AER
2012	-3.00	-4.00	-3.00	-4.00	-1.00	
2013	-3.00	-4.00	-3.00	-4.00	-2.00	
2014	-3.00	-5.00	-3.50	-5.00	-6.00	
2015	-3.00	-5.00	-4.00	-5.00	-6.00	

* Note that from 1996 to 2010, P-nought and X factor adjustments were determined in distribution price reviews by the Victoria regulator or Government (i.e. the Victorian tariff order, the ORG and the ESC). From 2011 onwards, this responsibility was assumed by the AER. Positive values for X indicate a real price decrease and negative values for X indicate a real price increase.
Source: Victoria Electricity Supply Industry Tariff Order June 1995, Electricity Distribution Price Review 2001-05 (Office of the Regulator-General) and Electricity Distribution Price Review 2006-10 (ESC), Final Decision on Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15 (AER).

Table 11 Real allowed P-noughts and X factors by distributor in New South Wales 1995-96 to 2014-15 (%)

	AusGrid (EnergyAustralia)	Endeavour (Integral Energy)	Essential (Country Energy)	Regulatory period
1995-96*	3.50	3.50	1.45	1995-96 to 1998-99: IPART
1996-97*	3.50	3.50	1.45	
1997-98*	3.50	3.50	1.45	
1998-99*	3.50	3.50	1.45	
1999-00*	0.00	0.00	0.00	1999-00 to 2003-04: IPART
2000-01*	0.86	1.47	-2.26	
2001-02*	0.86	1.47	-2.26	
2002-03*	0.86	1.47	-2.26	
2003-04*	0.86	1.47	-2.26	
2004-05*	-7.00	-5.00	-7.00	2004-05 to 2008-09: IPART
2005-06*	-1.60	-1.50	-2.50	
2006-07*	-1.60	-1.50	-2.50	
2007-08*	-1.60	-1.50	-2.50	
2008-09*	-1.60	-1.50	-2.50	
2009-10*	-17.86	-12.58	-13.41	2009-10 to 2013-14: AER
2010-11	-12.00	-7.00	-13.31	
2011-12	-12.00	-7.00	-12.00	
2012-13	-12.00	-2.00	-12.00	
2013-14	-8.00	0.00	0.00	
2014-15	-	-	-	-

* Note that from 1995-96 to 2008-09, P-nought and X factor adjustments were determined in distribution price reviews by IPART. From 2009-10 onwards, this responsibility was assumed by the AER. X factors for 2014-15 are not known as this forms part of the next regulatory period (2014-15 to 2018-19). Positive values for X indicate a real price decrease and negative values for X indicate a real price increase.
Source: NSW electricity distribution price determinations March 1996, December 1999, 2004-05 to 2008-09 (IPART) Final Decision on NSW distribution determination 2009-10 to 2013-14 (AER).

Table 12 Real allowed P-noughts and X factors by distributor in Queensland 1995-96 to 2014-15 (%)

	Energex	Ergon	Regulatory period
1995-96*	No X factors available, prices extrapolated according to changes in CPI	No X factors available, prices extrapolated according to changes in CPI	1995-96 to 1999-00: QLD Government
1996-97*			
1997-98*			
1998-99*			
1999-00*			
2000-01*	-9.50	-18.80	2000-01 to 2004-05: QCA
2001-02*	0.50	-5.90	
2002-03*	0.50	-0.30	
2003-04*	0.50	-0.30	
2004-05*	0.50	-0.30	
2005-06*	-11.90	-30.80	2005-06 to 2009-10: QCA
2006-07*	-11.90	-5.70	
2007-08*	-11.90	-5.70	
2008-09*	-11.90	-5.70	
2009-10*	-5.50	-5.70	
2010-11	-18.20	-29.61	2010-11 to 2014-15: AER
2011-12	-7.90	-5.10	
2012-13	-7.90	-5.10	
2013-14	-7.90	-5.10	
2014-15	-7.90	-5.10	

* Note that from 2000-01 to 2009-10, P-nought and X factor adjustments were determined in distribution price reviews by the QCA. From 2010-11 onwards, this responsibility was assumed by the AER. Positive values for X indicate a real price decrease and negative values for X indicate a real price increase. Data on X factors for the 1995-96 to 1999-00 regulatory period could not be obtained and where necessary, network tariffs have been escalated in accordance with changes in CPI.
Source: Final Determination on Regulation of Electricity Distribution May 2001 and April 2005 (QCA), Final Decision on Queensland distribution determination 2010-11 to 2014-15 (AER).

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