

December 2012

## Putting the customer back in front

How to make electricity cheaper

Tony Wood



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## Grattan Institute Report No. 2012-09, December 2012

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## Overview

Australians are paying too much for electricity because the regulation of distribution networks is broken. Fixing it will deliver savings to consumers of around \$2.2 billion per year, representing an annual saving to the average domestic customer of \$100 per year. This report explains how it should be done.

To give power back to consumers, governments need to reduce the outsized profits made by monopoly distribution businesses, empower the Australian Electricity Regulator to subject expenditure to a rigorous cost-benefit analysis, and transfer responsibility for reliability standards from governments to the Australian Energy Market Commission and the Australian Energy Regulator, the bodies that make and enforce the rules.

These monopoly businesses are allowed to make unduly high profits, given the relatively low risks they face. Governments have also intervened to ensure they deliver power at levels of reliability that no serious cost-benefit analysis can justify. The New South Wales, Queensland and Tasmanian governments have imposed extra costs on companies to address perceived reliability problems. Shifting responsibility for reliability standards to the AEMC and AER would minimise unnecessary political interference. Developing a national, consumer-centred approach to setting these standards is also vital.

Beyond these issues, flaws in the regulatory process have almost certainly led companies to over-invest in the network. The more they invest, the greater their potential return, yet the regulator has neither the resources to scrutinize these investments before they

are made, nor the power to penalize companies that over-invest. Governments should give the regulator these resources and power.

Finally, the system of five-year reviews of network prices cannot respond to changing electricity demand and finance costs. The regulator sets the revenue a company can collect from consumers over five years in order to fund its investment and costs. But real conditions change more quickly. For example, only a few years ago, the regulator allowed companies to spend to meet forecasts of rising energy demand and rising peak demand. For the first time in 40 years, both are falling, yet companies are receiving revenue based on the five-year forecasts. In other words, they are being funded for investments they no longer need to make.

Similarly, the regulator allows companies to set prices based on the projected cost of finance over five years. But when that cost falls, as it has done in recent years, the benefit is not passed on to consumers in lower prices. Governments should give the regulator more direction, resources and powers to review network expenditure forecasts and to adjust the allowed cost of company borrowing on an annual basis.

Electricity distribution networks are natural monopolies, so the laws of the pure market cannot apply. Although regulation is needed to ensure that companies have incentives to invest, recent changes to the way they operate have unduly disadvantaged the public. It is time to restore the balance.

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## 1. What we did and what we concluded

### 1.1 Why we wrote this report

Rising energy costs, electricity distribution costs in particular, have been a high-profile concern for consumers for several years. This report analyses the available data to examine the causes of these rising costs, whether these causes represent poor public policy, and where they do, how governments should respond.

The report does not seek to replicate the wide range of work already undertaken on these causes, and summarised in chapter 2. Instead, we test several hypotheses against the available data and then use our analysis to develop recommendations for change. These recommendations are ranked based on what would most address the flaws in the distribution system.

### 1.2 Our initial hypothesis

In early 2012, we reviewed recent reports from industry and regulatory bodies and interviewed a range of stakeholders. This led us to the hypothesis that recent and pending increases in electricity distribution costs are higher than they would be under efficient ownership and regulatory arrangements. This is due to:

- Businesses earning excessive rates of return, relative to their level of risk.
- Government ownership that leads to excessive capital investment and reduced productivity, among other

inefficiencies.

- Reliability standards that are higher than the benefits justify.
- A regulatory process that provides undue incentives for capital investment, leading to excessive expenditure without effective tests on prudential decision-making.

Our research used company-level data to test this hypothesis and the underlying causes. We have looked at peak demand in relation to its potential contribution to rising electricity prices. However, we have not examined the causes of changes in energy demand or peak demand or what governments might do to reduce future peak demand growth. We may return to the issue of demand management in a future project.

### 1.3 Our conclusions

The flaws in the regulatory process that force consumers to pay too much for electricity can and should be fixed. While achieving the objectives of the National Electricity Law is a complex challenge, our analysis finds that these flaws have unduly shifted the balance away from consumers and towards investors. They have led to avoidable costs to consumers of around \$2.2 billion a year. These costs will only escalate if changes are not made.

Our analysis identifies the following flaws:

- The allowed profits exceed reasonable levels for low-risk businesses such as the regulated electricity distribution networks in Australia's National Electricity Market.
- Costs have been incurred, and will continue to be incurred, to achieve levels of reliability that a robust cost-benefit analysis is unlikely to justify. Intervention by several governments to increase reliability standards has pushed up prices even more and led to calls for privatisation.
- The regulatory determination process has probably led to over-expenditure on capital assets. At present the regulator is only able to scrutinise company expenditure before it is made. Regulators do not have adequate resources to scrutinise expenditure, or powers to penalise over-expenditure.
- The process of five-yearly reviews of company price-setting locks in outcomes in a way that is no longer able to reflect the changing dynamics of the industry or the external financial environment. For example, expenditure was approved to meet forecasts of rising energy demand and peak demand. Both have fallen during the current five-year term, so this expenditure is unlikely to be necessary, yet businesses continue to receive revenue on the basis of the original forecasts.

Our analysis suggests that government-set reliability standards and intervention by treasury finance agencies has exacerbated these flaws. It also suggests that government-owned businesses have been less efficient than those in private ownership. Applying

more robust corporate governance to these businesses will deliver substantial cost reductions. Further gains may be achievable through privatising the businesses, though we recognise such a move may be politically challenging. Therefore, we consider corporate governance improvements to be a higher priority for immediate action.

The lack of availability of consistent data about the network businesses impedes effective economic regulation, not to mention analysis of the sort undertaken for this report. Since distribution businesses operate as regulatory monopolies, requiring greater disclosure would not have substantial commercial impacts. It would, however, increase the effectiveness of the regulator and independent commentators.

#### 1.4 Our recommendations

Our recommendations address the above flaws. We have quantified the benefits that would accrue to electricity consumers if the recommendations were adopted. Against the wider range of proposals that have been made recently by bodies such as the Australian Energy Market Commission and the Productivity Commission, we consider that these recommendations would have the greatest impact. This quantification is necessarily a crude estimation. Nevertheless, it provides a reasonable estimate of the scale of the benefit, and therefore the importance of implementing change:

1. The Australian Electricity Regulator should be directed to require businesses to only charge customers for the cost of company debt and equity at a level that is consistent with the risk profile of regulated monopoly businesses. The AER

should also be able to adjust these debt and equity risk premiums annually, in line with financial trends, instead of over a five-year period. Together, the changes to equity and debt calculations would have meant a net benefit to consumers of \$2 billion over the current five-year regulatory period. If no changes are made, and similar circumstances apply in coming years, the opportunity for similar savings – of around \$390 million a year – will be lost.

2. Governments should relinquish control over reliability standards and transfer responsibility for setting them to the AEMC and the AER. These bodies should develop a consistent national approach to setting standards based on comprehensive data on all classes of consumers. Reliability standards vary considerably across the NEM. Indeed, there have been so many changes in this area that it is difficult to quantify their impact on real reliability and prices. The changes we have recommended in this area would have avoided some costs incurred in the past and will avoid further costs in the future. We note that AEMO has estimated annual benefits from similar changes at around \$190 million in 2012-13.
3. Where state governments retain ownership of distribution businesses, they should clearly separate the roles of shareholder and financier, and establish robust governance structures, free from political interference. Implementing changes such that government-owned businesses would achieve similar levels of efficiency to currently-private businesses would deliver annual savings of around \$640 million from capital expenditure savings and \$500 million

in operating cost reductions.

4. Whilst five-year capital forecasts should remain in use, they should be updated annually in the light of any material changes to maximum demand forecasts provided by the Australian Energy Market Operator in its National Electricity Forecasting Report. The AER should also be able to subject all over-expenditure to a robust cost-benefit analysis after the expenditure has been made. If the reduced growth in electricity demand were to continue, and only half of the \$2.4 billion capital currently planned for new network capacity each year were required, then more responsive capital budgeting could save \$680 million a year within five years.

Capital expenditure savings achieved under the second and third of these changes would reduce those achieved under the first. Allowing for this adjustment, the total benefit could be around \$2.2 billion per year.<sup>1</sup> This could represent savings to individual consumers of about \$100 per year, on average across the NEM.<sup>2</sup>

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<sup>1</sup> \$5.4 billion reduction in the NEM asset base equates to 12% of the total, and therefore a 12% reduction in the savings under the first item.

<sup>2</sup> Based on 35% of energy going to residential customers and residential customers representing 85% of total customers.

**Figure 1.1: Potential NEM-wide annual savings**

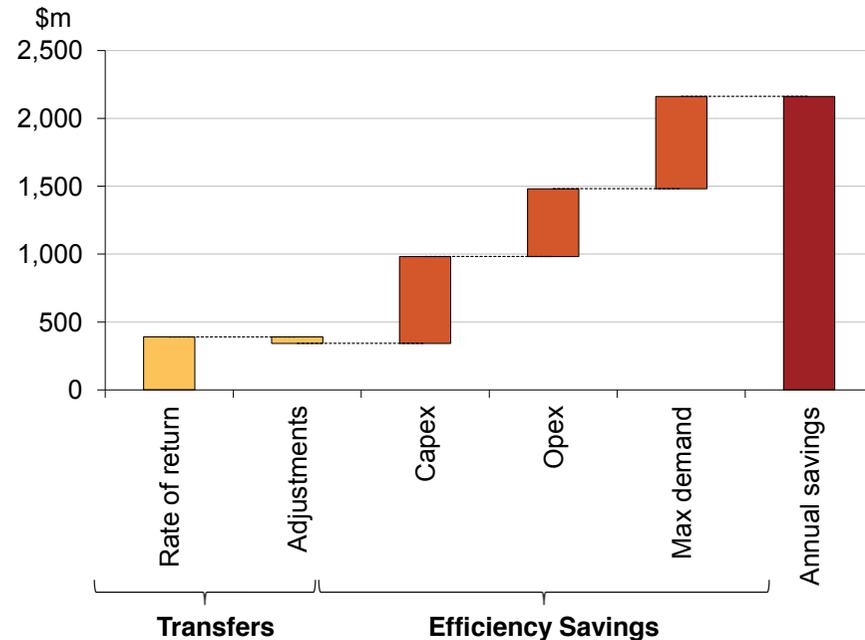


Figure 1.1 shows the potential NEM-wide annual savings from implementing the recommendations in this report. The savings identified in the above chart as 'efficiency savings' would be passed on, in full, to electricity consumers. These changes would deliver a total saving of \$1.8 billion per year. Also, in states with privatised distribution businesses, consumers would receive the full benefit of savings from lower rates of return. However, the full benefit to consumers from a lower rate of return may be offset where the state government owns the distribution business. The offset would occur though state governments increasing taxes or

reducing spending due to the fall in revenue. Savings due to lower rates of return may thus include 'transfers', because electricity users are also tax payers.

We note that several of the recommendations above are the subject of recent and current reviews by the AEMC and the Productivity Commission respectively. Our recommendations are generally consistent with these reviews. However, we are concerned that the rule changes proposed by the AEMC are too high-level in their direction to the AER. To date, the results of rule setting and enforcement have led to poor outcomes for consumers. The magnitude of the problem suggests that more direction is both required and justified.

These comments and the entire report apply only to the NEM, comprising Queensland, New South Wales, the Australian Capital Territory, South Australia, Victoria and Tasmania.

## 2. Mission control, we have a problem

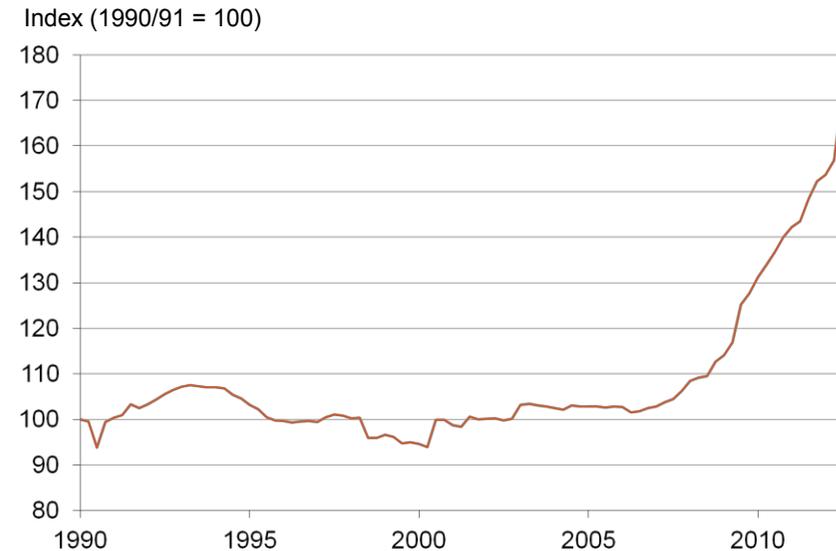
### 2.1 What has happened?

For many years, energy costs in Australia were low by world standards, affordable in relation to average incomes and relatively stable. However, in the last six to seven years this has changed.

Figure 2.1 shows that rapid increases in the power bills of consumers supplied by the National Electricity Market are well above CPI and growth in average incomes. Most blame has fallen on the costs of distributing electricity through networks of substations, poles and wires across our cities and towns.

Figure 2.2 shows how much of this component of total electricity costs is paid by domestic consumers, and how it has grown over time. In figure 2.2, 'network' costs include both transmission and distribution. Distribution accounts for approximately 40 per cent of retail prices, whereas transmission accounts for approximately 10 per cent.<sup>3</sup> Distribution is forecast to contribute up to 40 per cent of price increases by 2013-14, while transmission will contribute up to 15 per cent.<sup>4</sup>

Figure 2.1: Growth in electricity retail prices



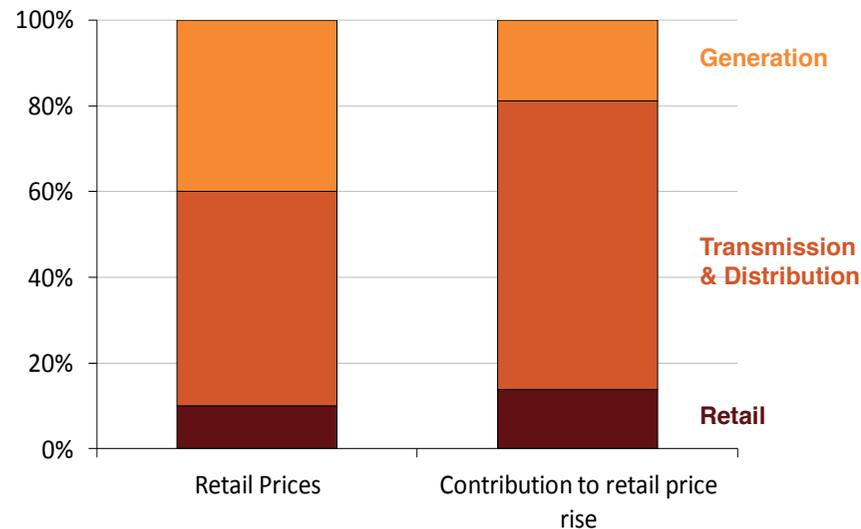
Source: Australian Bureau of Statistics (2012)

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<sup>3</sup> Garnaut (2011), p 8

<sup>4</sup> AEMC (2011) cited in Productivity Commission (2012), p 104

Figure 2.2: Contribution of network costs to retail prices (2010)



Source: Garnaut (2011), p9

These increases have generated concerns from all classes of electricity consumers, all levels of government, various government agencies and the electricity supply industry itself. Several recent and current reviews, described below, have concluded that while many costs have risen to meet real needs, significant flaws in the regulatory processes have led to unjustified cost increases. It is unfortunate, but not unexpected, that some of the public commentary about these reviews has resorted to blaming and point scoring. The economic regulation of natural monopoly electricity distribution businesses is complex and often

politically sensitive. The regulator seeks to achieve a balance between the interests of investors and those of consumers. It is now a widely accepted conclusion that the balance has shifted towards the former and that there needs to be a correction.

Recommendations to address these flaws range from fundamental structural change to the ownership and governance of the industry, to changes in the rules and processes by which regulatory agencies determine the costs that the businesses can charge consumers.

At the time of publication, it is unclear whether and how the Australian Government, States and Territories, and various government agencies will introduce changes that will deliver the greatest benefit to the greatest number of Australians.

## 2.2 How did we get here?

At the end of the 1980s, electricity was delivered by government-owned, vertically integrated supply businesses that were responsible for the generation, transmission, distribution and retailing of electricity in each state and territory. During the 1990s, Australian Governments, encouraged by the recommendations of the 1993 Hilmer Review of National Competition Policy, began to break up the elements of the supply chain and introduce competition in the generation and retail segments.<sup>5</sup> Since then, several rounds of privatisation of retail and generation businesses have taken place; Victoria also privatised distribution. The goal was to reduce costs for consumers through competition, without sacrificing reliable supply.

<sup>5</sup> Hilmer, *et al.* (1993)

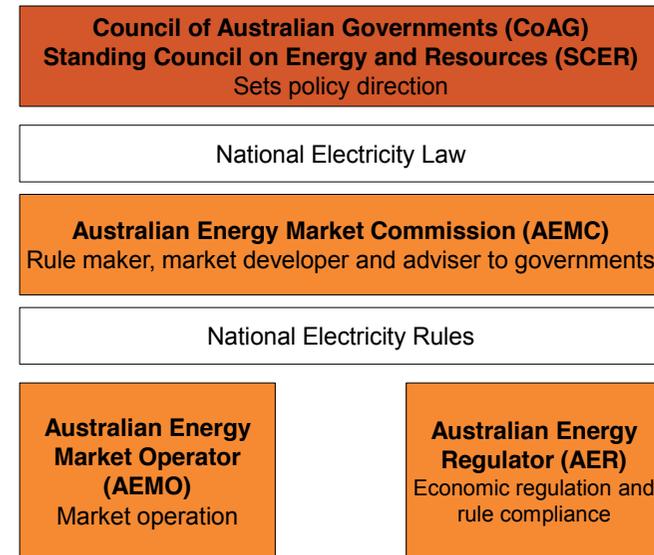
Whilst privatisation has not always been politically popular, the evidence of relative price stability and supply reliability in the privatised sectors suggest it has worked. However, not all states and territories have completed the journey: retail price deregulation remains an unachieved but stated intent in most jurisdictions, with the notable exception of Victoria where it was completed during the last decade.

As shown in figure 2.2, the largest segment of consumer costs, and the one making the greatest contribution to price rises, is distribution. This report focuses on that segment.

Electricity distributors are classic monopoly businesses - increasing scale through a single provider reduces costs to a degree that could not be achieved through competition.<sup>6</sup> Most of a distributor's costs lie in the infrastructure assets it builds and operates in order to transport electricity. These generally have effective lives of several decades, meaning that investment decisions by companies will have cost implications for a long time. The independent Australian Energy Regulator (AER) determines the acceptable level of costs that can be passed through to consumers by distributors. The AER works within a set of rules determined by the Australian Energy Market Commission (AEMC). The AEMC in turn operates under the direction of a ministerial council, the Standing Council on Energy and Resources and, ultimately, the Council of Australian Governments (CoAG). Figure 2.3 shows the Australian electricity regulatory structure.

<sup>6</sup> Baumol (1977), Depoorter (1999)

Figure 2.3: Governance structure of the National Electricity Market



Source: AEMC (2012a), p .

The overarching legislative instrument is the National Electricity Law (NEL), which aims:

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:

1. price, quality, safety, reliability, and security of supply of electricity; and

2. the reliability, safety and security of the national electricity system.

The final piece in the picture is the Australian Competition Tribunal, which can hear parties' appeals to AER determinations.

In 2008, the AER assumed responsibility for economic regulation from state and territory regulators. The AER determines forward prices for a period of five years, so distributors are now in either the first or second period of regulation under the AER. The regulatory framework remains relatively new and continues to evolve.

In the National Electricity Market, the Queensland, New South Wales and Tasmanian governments own the distributors. In Victoria and South Australia they are owned by private companies. In the Australian Capital Territory the company structure is a joint venture between ACTEW Corporation, an Australian Capital Territory Government-owned enterprise, and AGL Energy. Table 2.1 provides detail on distribution network characteristics.

There are concerns that political interference and a lack of clear separation of roles have imposed costs on government-owned distributors that would not have been incurred if the companies had been privately owned. Our report examines this issue.

**Box 2.1: Building block approach to determining companies' allowable revenue**

The AER uses a 'building block' approach to determine the total revenue a distributor will receive over a five-year regulatory period. This revenue should enable distributors to provide investors with a reasonable rate of return and deliver an efficient and reliable service. The components that build to this total in each year are:<sup>7</sup>

The depreciation cost, based on the value of regulated assets, which is called the 'Regulated Asset Base' (RAB). Capital expenditure increases the value of the RAB in future years.

Return on capital (the Weighted Average Cost of Capital, or WACC), which includes the cost debt repayments and providing equity returns.

Operating expenditure.

Corporate income tax.

Changes in revenue due to regulatory incentives.

Capital expenditure, both past and forecast, is the largest determinant of the allowed revenue.

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<sup>7</sup> National Electricity Rules cl 6.4.3, AEMC (2009)

**Table 2.1: Electricity distribution companies in the National Energy Market**

State	Company	Ownership	Number of customers	Km Line	Current determination period	RAB (2010 \$m)*
ACT	ActewAGL	50/50	157 635	4 858	2009-10-2013-14	617
NSW	AusGrid	Government	1 605 635	49 442	2009-10-2013-14	8 688
	Endeavour	Government	866 724	33 817	2009-10-2013-14	3 803
	Essential Energy	Government	801 913	190 844	2009-10-2013-14	4 277
QLD	Energex	Government	1 298 790	53 256	2010-11-2014-15	7 867
	Ergon	Government	680 095	146 000	2010-10-2014-15	7 149
TAS	Aurora	Government	271 750	24 385	2012-13-2016-17	1 105
SA	SA Power Networks	Private	817 300	87 220	2011-2015	2 772
VIC	Citipower	Private	308 203	6 506	2011-2015	1 273
	Jemena	Private	309 505	5 971	2011-2015	748
	SP AusNet	Private	623 307	48 259	2011-2015	1 774
	Powercor	Private	706 577	84 027	2011-2015	2 362
	United Energy	Private	634 508	12 628	2011-2015	2 016
<b>TOTAL</b>			<b>9 081 942</b>	<b>747 213</b>		<b>44 079</b>

\* The regulated asset bases are as set at the beginning of the current regulatory period for each network.  
 Source: Australian Energy Regulator (2011b), Australian Energy Regulator (2012a)

### 2.2.1 The range of reviews and reports

Over the last year or so, several reviews and reports by government agencies and other bodies have reported or commented on the impact and causes of, and potential actions to address, rising electricity distribution costs. Here we summarise the key points some of these reports make.

In its *State of the Energy Market 2011* report, the Australian Energy Regulator suggested that rising network costs have been driven by the growth in peak energy demand, stricter reliability and safety standards imposed by governments, growth in customer numbers, the need to replace ageing equipment, and higher debt costs.<sup>8</sup> The AER also maintained that the regulatory framework introduced in 2006 has restricted its capacity to assess the efficiency or necessity of investments, and that this has “led to consumers paying more than is necessary for a safe and reliable energy supply”.<sup>9</sup> In late 2011, the AER proposed changes in the rules that it said would address these deficiencies.<sup>10</sup>

In November, 2012, the AEMC made its final determination on the rule change request made by the AER and the Energy Users Rule Change Committee to improve and strengthen the rules under which the AER regulates the network businesses. It proposes changes to address concerns about the way in which rates of return are determined, the incentives for efficient network expenditure and the level of scrutiny of such expenditure, as well

as several changes to improve the transparency and timeliness of the process by which regulatory outcomes are determined.<sup>11</sup>

In August 2012 a Senate Select Committee on Electricity Prices was established. It was to inquire into and report on a range of issues, including:

- identification of the key causes of electricity price increases over recent years and those likely in the future;
- legislative and regulatory arrangements and drivers in relation to network transmission and distribution investment decision making and the consequent impacts on electricity bills, and on the long term interests of consumers;<sup>12</sup>

In its report, released in November 2012, the Committee concluded that regulation of the NEM “creates a perverse incentive for network businesses to engage in inefficient over-investment.”<sup>13</sup> It recommended increasing the capacity of the AER to scrutinise network business investment proposals by:

- Adopting new guidelines for assessing rates of return and requiring that these guidelines are reviewed every three years;
- Changing the National Electricity Rules to ensure more efficient forecasting of capital returns, return on debt, and

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<sup>8</sup> Australian Energy Regulator (2011b), p4

<sup>9</sup> Ibid., p 4

<sup>10</sup> Australian Energy Regulator (2011a)

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<sup>11</sup> AEMC (2012e)

<sup>12</sup> The Senate Select Committee on Electricity Prices (2012), p 1

<sup>13</sup> Ibid. p xi

capital and operational expenditure, as well as decoupling network revenues from energy volumes;

- Giving network businesses greater guidance for tariff-setting; and
- Empowering the AER to conduct reviews of network business capital expenditure after the fact.<sup>14</sup>

In January, 2012, the Australian Government asked the Productivity Commission to undertake a 15-month public inquiry into aspects of national electricity network regulation. The terms of reference require the Commission to identify whether there are “any practical or empirical constraints on the use of benchmarking of network businesses and then provide advice on how benchmarking could deliver efficient outcomes consistent with the National Electricity Objective (NEO)”.<sup>15</sup>

The Commission published a draft report on 18 October.<sup>16</sup> Its recommendations go well beyond the benchmarking issue to propose a more fundamental package of reforms to reliability standards, business ownership and the role of the regulator, as well as greater focus on the interests of consumers.

In March 2012 the Standing Council on Energy and Resources appointed an expert panel to review the process by which the AER’s decisions could be reviewed at the request of affected parties. This panel, which delivered its report in September, 2012,

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<sup>14</sup> Ibid., p xi

<sup>15</sup> Productivity Commission (2012), p iv

<sup>16</sup> Ibid.

concluded that the review process is constrained, to the long term detriment of consumers.<sup>17</sup> It recommended major changes to the review process to better incorporate consumer interests. It also proposed governance changes, including the separation of the AER from the AEMC. The panel went beyond the confines of its remit to identify other problems, including ongoing public ownership of networks and the need for more sophisticated network pricing to provide greater incentives for demand management.

As well as these formal reports, several public presentations and reports have addressed various aspects of electricity network regulation. They include Rod Sims, the Chairman of the Australian Competition and Consumer Commission,<sup>18</sup> Professor Ross Garnaut in his 2011 update to the Garnaut Climate Change Review and submissions by researchers such as Bruce Mountain and Ross Littlechild.<sup>19</sup> There is little doubt that Garnaut significantly increased the general visibility and priority regarding key issues around ownership.

In general, all the reports have found much to criticise, and agreed that major changes are required to address a shift in the balance of outcomes back towards the interests of consumers.

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<sup>17</sup> Standing Council on Energy and Resources (2012)

<sup>18</sup> Sims (2012)

<sup>19</sup> Garnaut (2011); Mountain and Littlechild (2010); Mountain (2012), Mountain (2011)

### 2.2.2 The claims of the industry

In formal submissions and direct interviews, the distributors have argued that current levels of capital and operating expenditure have been required to:<sup>20</sup>

- meet the rising demand for electricity at peak times;
- replace aging assets;
- meet reliability standards; and
- reflect higher costs of borrowing.

They maintain that much of the expenditure has been necessary and appropriate or has been driven by requirements imposed on the companies by governments or regulatory bodies, or both.

### 2.3 What are the important issues that need to be addressed?

There is no debate that economic regulation of monopoly distribution businesses is necessary. Nor that the process of regulation should produce efficient investment in and operation of the networks. Rather, concerns have been raised about the way in which the objectives are translated into rules and practice. This is a complex area of policy and practice and the current structure and processes are still evolving. However, the cost impact on consumers in recent years has been high enough to conclude that changes in key areas would deliver significant benefits.

The following four chapters examine the issues of cost of finance, government ownership, reliability standards and the regulatory process to identify specific problems and recommendations as summarised in chapter 1.

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<sup>20</sup> Energy Networks Association (2012), p 7

### 3. Deciding on a fair return

#### 3.1 Summary and recommendations

The Australian Electricity Regulator sets rates of return that allow distributors to earn enough revenue to cover their reasonable costs of debt and equity.

If a distributor's allowed cost of equity or debt is set too high, this will enable it to charge consumers higher prices than an efficient distributor would need in order to recover its financing costs. Setting these costs too high over time may also create an incentive for overinvestment, because money will chase the above-market returns that these distributors may provide.

On the other hand, if the costs are set too low the distributor will not be able to attract the capital it needs to function. The risk of underinvestment in the network explains why the regulator has allowed distributors to recover high financing costs.<sup>21</sup> But the evidence suggests the balance has swung too far, and that distributors are being over-compensated for the financing costs that they bear. The result is unduly high prices for consumers.

The analysis in this chapter finds that:

- The regulator is biased towards granting distributors an excessively high equity risk premium. This results in profits

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<sup>21</sup> For example, see introductory remarks to the Statement of Regulatory Intent regarding equity market risk premium and beta: Australian Energy Regulator (2009a), p iii. For an overseas example, see Commerce Commission (NZ) (2011), p 2

that are higher than is justified by the actual risk to which these businesses are exposed.

- The regulator has allowed distributors to recover costs of debt that are higher than both their actual costs of debt and the cost that a benchmark efficient distributor would incur.

In order to quantify the savings that would be made if these flaws were addressed:

- We estimate the reductions in distributor revenue that would have occurred if the regulator had assessed the distributor's cost of equity in line with a business that faced a comparable level of risk. The regulator itself accepted an empirical range of risk parameters for distributors – then took an even more conservative approach. An assessment of distributors' level of risk at the top of this empirical range, applied over the period 2009-10 to 2014-15, would have produced savings to customers of about \$240 million per year in 2010 dollars.
- We estimate the actual costs of debt paid by distributors, and calculate the reductions in revenue that would have occurred if the costs had been estimated by a moving average of a benchmark of comparable commercial debt rates. Applied over the period 2009-10 to 2012-13, this approach would have produced savings to customers of about \$170 million per year in 2010 dollars.

The full benefit to consumers from lower costs of debt and equity may be offset where the state government owns the distribution business. The offset would occur though state governments increasing taxes or reducing spending due to the fall in revenue.

Any change in approach should take into account the combined effect on distributor income of setting new parameters for equity and debt. The application of an equity risk premium just beyond the top of the empirical range should guard against this risk.

We recommend that the regulator uses its updated powers under the proposed changes to the National Electricity Rules<sup>22</sup> to:

- Estimate the allowed rate of return for equity taking into account prevailing market conditions for equity funds and observed returns for a range of companies. This would be consistent with the AEMC's recent change to the NER, developed in response to proposals by energy user groups.<sup>23</sup> If distributors continue to earn higher-than-expected equity returns, these powers should be used to apply parameters that strike a better balance between investment risk and consumer prices than currently exists.
- Implement a cost of debt approach that is more likely to reflect a benchmark efficient distributor's actual financing costs by incorporating a moving average of benchmark debt rates. Again, this approach would be consistent with the AEMC's proposed changes to the National Electricity Rules, in particular the allowance for the use of historical moving

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<sup>22</sup> AEMC (2012e)

<sup>23</sup> AEMC (2012g), 6.5.2 (e) (2)

averages<sup>24</sup> and the direction to the AER to take note of the significant differences between the allowed return and the debt servicing costs of a benchmark-efficient distributor.<sup>25</sup>

### 3.2 Background

The National Electricity Rules require that the return a distributor can earn on its regulated asset base<sup>26</sup> over a regulatory period be set as follows:<sup>27</sup>

*The rate of return ... is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business of the provider and must be calculated as a nominal post-tax weighted average cost of capital (WACC) in accordance with the following formula:*

$$WACC = r_{equity} \frac{E}{V} + r_{debt} \frac{D}{V}$$

In the WACC formula,  $r_{equity}$  is the allowed return on equity (or 'cost of equity') and  $r_{debt}$  is the allowed cost of debt, both expressed as percentages per annum.<sup>28</sup>

$E/V$  is the ratio of equity value to total company value, and  $D/V$  is the ratio of debt value to total company value, i.e. the level of gearing. These are set at 40 and 60 per cent respectively.<sup>29</sup>

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<sup>24</sup> Ibid., 6.5.2 (g)

<sup>25</sup> Ibid., 6.5.2 (h) (1)

<sup>26</sup> AEMC (2012f) 6.5.2 (a)

<sup>27</sup> Ibid. 6.5.2 (b)

<sup>28</sup> We have used 'r' rather than 'k' (as per the NER) to represent costs.

### 3.3 Cost of equity

#### 3.3.1 Estimation under the National Electricity Rules

Under the NER, the allowed rate of return for equity is estimated using the Sharpe-Lintner Capital Asset Pricing Model (CAPM) formula:<sup>30</sup>

$$r_{equity} = r_{risk-free} + \beta_{equity} \times \text{Market Risk Premium}$$

The standard CAPM formula states that the return on equity for an asset should have two components:<sup>31</sup>

1. The risk-free rate of return, which is usually estimated by the yield on some form of very-low-risk asset, such as a government bond.
2. A premium to compensate for market risk: an 'excess return' over and above the risk-free return. This is calculated by multiplying the asset's 'equity beta' (the extent to which its returns are linked to those of the broader market) by the market's excess returns – the 'Market Risk Premium'. The Market Risk Premium is normally calculated as the long-term excess return earned by a broad equity market index, e.g. the Australian Stock Exchange All Ordinaries. The beta is generally estimated by performing a regression analysis of the asset's historical excess returns against those of the market.

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<sup>29</sup> Australian Energy Regulator (2009b), p 7

<sup>30</sup> AEMC (2012f) 6.5.2 (b)

<sup>31</sup> See Fama and French (2004) for a detailed discussion of the CAPM

#### Risk-free rate

The AER sets the risk-free rate using a moving average, typically over 10 to 40 days,<sup>32</sup> of the yield of Australian Commonwealth Government Securities with a maturity of ten years.<sup>33</sup> In its 2009 Statement of Regulatory Intent, the AER considered whether to use a maturity term matching the five-year regulatory period, but concluded that the 10-year Commonwealth Government Security remained the most appropriate proxy for the risk-free rate given the long-term nature of the investments made by utilities such as distributors.<sup>34</sup>

#### Market risk premium

In its 2009 Statement of Regulatory Intent, the AER specified a market risk premium of 6.5 per cent.<sup>35</sup> This is broadly consistent with the consensus amongst regulators, academics and financial markets practitioners about the value of the long-term equity market risk premium in Australia. The AER notes that its use of a relatively high value within the consensus range "is appropriate having regard to the economic costs and risks of the potential framework in under and over investment".<sup>36</sup> It is supported by historical studies by academics such as Officer<sup>37</sup> and Brailsford & Handley<sup>38</sup> and surveys of financial markets participants.<sup>39</sup>

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<sup>32</sup> Australian Energy Regulator (2009a), p xiii

<sup>33</sup> AEMC (2012f) 6.5.2 (d) and Australian Energy Regulator (2009b), p 7

<sup>34</sup> Australian Energy Regulator (2009a), p 172

<sup>35</sup> Australian Energy Regulator (2009b), p 7

<sup>36</sup> Australian Energy Regulator (2009a), p 238

<sup>37</sup> Officer (1994)

<sup>38</sup> Brailsford, *et al.* (2008)

## Equity Beta

Beta values are estimated empirically by performing a regression analysis of the observed excess returns from listed companies against the market's excess returns. This measures the extent to which the companies' excess returns match those of the market. For example, a company with a beta of 1.0 would have excess returns perfectly correlated with those of the broader equity market.

The companies chosen are those with comparable characteristics to the distributors. Where possible this includes distributors that are listed on the stock market, but in Australia this calculation is restricted by their small number and complicated ownership structures.

Prior to 2009, the AER and earlier state-based regulators applied beta values of 0.9-1.0.<sup>40</sup> In its 2009 Statement of Regulatory Intent the AER noted that empirical studies of the beta value for distributors have generally resulted in ranges of approximately 0.41-0.68.<sup>41</sup> Nevertheless, the AER concluded:

*Market data suggests a [beta] value lower than 0.8. However, the AER has given consideration to other factors, such as the need to achieve an outcome that is consistent with the*

*importance of regulatory stability. Having taken a broad view, the AER considers the value of 0.8 is appropriate.*<sup>42</sup>

The AEMC's 2012 draft rule change discusses a number of weaknesses of the CAPM approach, noting considerable criticism in the academic literature.<sup>43</sup> The AEMC has urged the AER to be more flexible in "taking into account the prevailing conditions in the market for equity" when it determines the cost of equity.<sup>44</sup> Yet while acknowledging the weaknesses of the CAPM model, the AER has maintained that it is a reasonable model and appropriate for use.<sup>45</sup>

The beta value of 0.8 quantifies the equity's exposure of a distributor to systemic market risk. The CAPM formula determines the appropriate return that an equity investor should demand in return for accepting this risk. Where an investment has a lower exposure to market risk, the investor must accept a lower return.

Nevertheless, in practice distributors have earned returns on equity that are higher and less volatile – that is, less risky – than companies in related industries and the overall equity market.

We have plotted the mean and standard deviation (which represents risk) of the returns on equity for the distributors, a number of other companies in the energy industry (including vertically integrated electricity generation and retail companies, and gas producers), and on the ASX Utilities index. We would

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<sup>39</sup> Summaries discussed in Australian Energy Regulator (2009a), p 221

<sup>40</sup> Ibid., p v

<sup>41</sup> Ibid., p 343

<sup>42</sup> Ibid., p 343

<sup>43</sup> AEMC (2012c), p 47

<sup>44</sup> AEMC (2012g), p 608

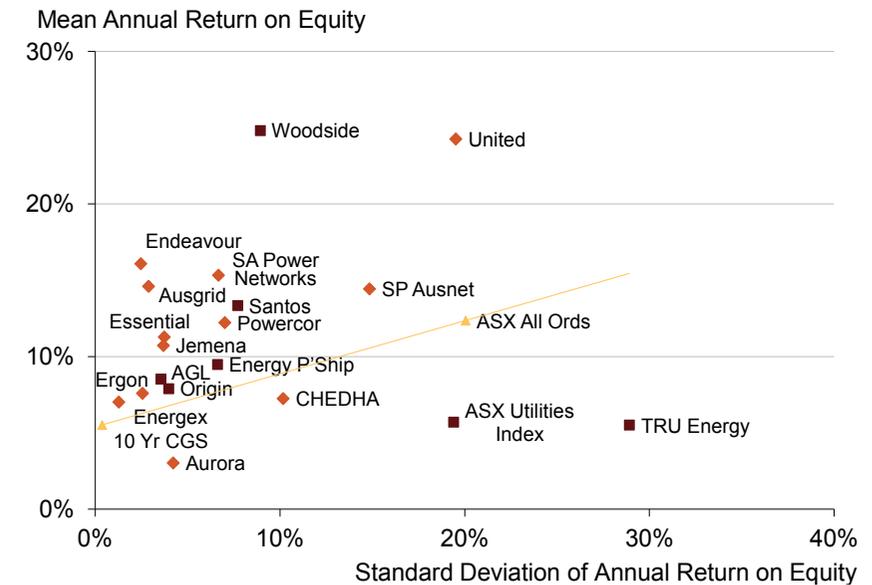
<sup>45</sup> Australian Energy Regulator (2009a), p 343

expect such non-monopoly business to earn higher returns on equity as compensation for the greater risks (in the form of volatility of returns) they face.

We have also shown the mean risk-free and equity market returns (using the yield on Australian 10 Year Commonwealth Government Securities and the ASX All Ordinaries index as respective proxies).

The chart shows that the distributors have generally provided higher equity returns with lower volatility – or risk -- than other equity investments, rather than the lower but less risky returns anticipated by the beta value less than 1.<sup>46</sup>

Figure 3.1 - DNSP equity returns and volatility



Sources: Analysis of data obtained from Bloomberg; Standard & Poor's and company reports. Data period: 2004-2011 except where not available from company.

<sup>46</sup> Given the small sample period for which data on the distributors are available, these results should be treated carefully. Several of the government-owned distributors had retail operations in the earlier portions of the sample period, and we would therefore expect higher risk given the greater business risks energy retailers face. We recommend care in adjusting the WACC parameters, as discussed in our conclusions above.

### 3.3.2 Potential impact of changes in beta

In order to illustrate the effect of the beta parameter on the cost of electricity borne by consumers, we have calculated the reductions in allowed revenues that would have resulted had the regulator used a beta of 0.7 in the most recent round of determinations. We have chosen a value of 0.7 because it represents the high end of the range of values that the AER observed in its survey of empirical studies.

We present the expected reductions in revenue due to the resulting change in the weighted average costs of capital (WACCs) in table 3.1 below.

Where determinations have prescribed a range for the value of beta, we have used the mid-point of that range. We note that regulators may choose a point nearer the higher end of the range to recognise the greater downside risk to investment of too-low returns on equity.<sup>47</sup> In some cases our approach may thus underestimate the revenue reduction that would have resulted.

Revenue reductions are expressed in 2010 dollars. The determinations for NSW and Queensland for 2014/15 and beyond are not yet available.

Table 3.1: Revenue reductions assuming beta of 0.7

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
ActewAGL	\$4M	\$4M	\$5M	\$5M	\$5M	N/A
Ausgrid	\$41M	\$57M	\$64M	\$72M	\$79M	N/A
Endeavour Energy	\$24M	\$28M	\$31M	\$33M	\$35M	N/A
Essential Energy	\$23M	\$33M	\$37M	\$40M	\$44M	N/A
Energex	\$35M	\$21M	\$19M	\$23M	\$25M	N/A
Ergon	\$34M	\$20M	\$17M	\$20M	\$22M	N/A
ETSA	\$13M	\$7M	\$8M	\$8M	\$8M	N/A
Aurora	\$5M	\$5M	\$6M	\$3M	\$3M	N/A
Citipower	\$23M	\$3M	\$3M	\$4M	\$4M	\$4M
Jemena	\$16M	\$2M	\$2M	\$2M	\$2M	\$2M
Powercor	\$38M	\$5M	\$6M	\$6M	\$6M	\$7M
SP AusNet	\$35M	\$5M	\$5M	\$6M	\$6M	\$7M
United Energy	\$25M	\$3M	\$4M	\$4M	\$4M	\$4M
<b>Total (2010 \$)</b>	<b>\$317M</b>	<b>\$195M</b>	<b>\$206M</b>	<b>\$226M</b>	<b>\$244M</b>	<b>\$24M</b>

Notes: Victorian determinations apply to calendar years, e.g. the 2009-10 year column refers to the Victorian year commencing 1 January 2010.

Sources: Analysis of data from Australian Energy Regulator (2012a).

<sup>47</sup> See introductory remarks to the Statement of Regulatory Intent regarding equity market risk premium and beta, Australian Energy Regulator (2009a), p iii

### 3.4 Cost of debt

The National Electricity Rules require that the amount of money a distributor can charge its customers for the cost of its debt should reflect the cost that a benchmark efficient distributor would incur.<sup>48</sup>

Under the Rules, the AER determines the cost of debt as the sum of the risk-free rate (calculated in the same manner as for determining the cost of equity) and the debt risk premium.<sup>49</sup>

*The debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency.<sup>50</sup>*

#### 3.4.1 Focus

We focus on three issues related to the costs of debt applied in recent determinations:

#### Over-compensation for actual costs of debt

During recent regulatory periods, the allowed costs of debt appear to have been consistently higher than the actual costs of debt paid by distributors during recent regulatory periods. This includes government-owned distributors, which had actual costs of debt

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<sup>48</sup> See the review criteria in AEMC (2012f), 6.5.4 (e)

<sup>49</sup> Ibid., 6.5.2 (b)

<sup>50</sup> Ibid., 6.5.2 (e)

that appear considerably lower than the regulated costs even when competitive neutrality fees were taken into account.<sup>51</sup>

#### Long-term 'lock-in' of costs of debt

Instead of matching the actual costs of debt paid by distributors, the National Electricity Rules state that the determined rate of return should be “a forward-looking rate of return that is commensurate with prevailing conditions in the market for funds”<sup>52</sup> and that “the return on debt [should] reflect the current cost of borrowings for comparable debt”.<sup>53</sup> In our view this fails to take into account the impact of actual financing practices on a distributor’s effective cost of debt.<sup>54</sup>

Regulated costs of debt are fixed at the start of each five-year regulatory period. But distributors rarely raise their entire debt funding at the start of a regulatory period. Rather, they maintain a portfolio of borrowings with different terms and interest rates. They manage this portfolio over time, repaying debt as it becomes due and issuing new debt as required.<sup>55</sup> Therefore the prevailing costs of debt at the time of the regulatory determination are

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<sup>51</sup> QTC and NSW T-Corp charge government-owned corporations (GOCs) competitive neutrality fees on their borrowings. These compensate for the difference between the treasury corporations’ borrowing rates and the market rates for borrowers with the same credit rating that the relevant GOCs would have on a standalone basis.

<sup>52</sup> AEMC (2012f), 6.5.4 (e) (1)

<sup>53</sup> Ibid., 6.5.4 (e) (2)

<sup>54</sup> We note a similar conclusion (that it is not practicable for a DNSP to implement the financing approach implied in the current rules) in the AEMC’s consultant’s report: SFG Consulting (2012), p 5

<sup>55</sup> Company financial reports provide individual DNSPs’ debt maturity profiles.

unlikely to reflect the actual costs of debt the distributor will face over the subsequent regulatory period.

The effects of such 'lock-ins' can be seen in the unusually high debt risk premiums that were observed during and following the Global Financial Crisis in late 2008 and 2009. Determinations of the cost of debt made at this time risked being upwardly biased by the high – but temporary – debt risk premiums prevailing in the market. As distributors did not immediately refinance their entire portfolios while these rates prevailed, their costs of debt over the subsequent period did not reflect these higher rates in their entirety.<sup>56</sup>

The AEMC's consultant agrees that determined and actual costs of debt will differ, but that this risk is symmetrical and customers and distributors are simply on each side of it.<sup>57</sup> While one or the other could experience a windfall profit or loss in any given regulatory period, neither could thus be expected to realise them consistently over time. While acknowledging this, our empirical analysis suggests that in recent regulatory periods the regulated costs have consistently overestimated the actual debt costs faced by distributors. This is the case even if regulated costs have accurately accounted for the costs of newly-issued debt issues as per the rules.

For customers to receive windfall gains, the distributor would need to be 'locked in' to a lower rate than it was actually facing, a situation likely only in the event of a persistent increase in the costs of debt. In such a case an efficient distributor has at least

some opportunity to proactively manage its capital structure to mitigate rising costs as best it can. In the alternative event of windfall gains to the distributor, customers have little ability to manage their losses and the distributor has no incentive to do so. This asymmetry hurts customers.

Were a distributor to experience windfall gains and losses in different regulatory periods, we could expect the subsequent volatility in earnings to justify a higher required return on equity. This would also flow through into higher costs for consumers.

A Queensland Treasury Corporation submission to the AEMC rule change review observed that recent debt issues by distributors have been priced at debt premiums that broadly reflect the regulated cost of debt (once the shorter terms available since the GFC have been accounted for).<sup>58</sup> We note that:

- The sample incorporated debt issues over 2008-2011. These issues raised a total of approximately \$6 billion, of which about \$3.6 billion was considered relevant due to the absence of parent company credit support. The total included a number of issues by gas or portfolio-based companies as well as distributors. As of 2011 the total debt held by distributors was about \$40 billion. So the sample only reflects the relatively small portion of this total pool debt that was exposed to prevailing debt market prices.
- A number of the sampled issues with higher debt risk premiums were made by companies either partially or fully involved in gas transmission. The greater risks of the gas

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<sup>56</sup> See our DNSP-specific analysis in appendix 2.

<sup>57</sup> SFG Consulting (2012), p 5

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<sup>58</sup> Queensland Treasury Corporation (2012), p 16

transmission business, including greater exposure to volume risk, imply that these businesses ought to face higher debt risk premiums. The average debt risk premium presented is thus biased upwards by the inclusion of these businesses.

The submission demonstrates the conflict between the current approach of performing a forward-looking estimate (which the submission suggests accurately estimates the likely costs of raising new debt) and the actual costs of debt faced by distributors on their full debt portfolios.

Further submissions to the AEMC directions paper asserted that differences between determined and actual costs of debt were due to the shorter terms and corresponding lower rates available after the GFC.<sup>59</sup> The submissions argued that the equivalent rates for longer-term debt were equivalent or greater to the determined costs. The AER rejects this position.<sup>60</sup>

As with our comments on QTC's submission, we note that regardless of the relationship between determined and actual costs of new debt issues, they account for a relatively small portion of the distributors' outstanding debt and do not necessarily reflect the impact of their financing practices on their actual costs of debt.

### Related party debt

Several Victorian and South Australian distributors are partially financed by particular forms of debt sourced from their owners or

other related parties, such as subordinated loans or preference shares. This debt is generally held by equity-holders, and is often explicitly linked to equity, e.g. through 'stapling' to the shares in the distributors.<sup>61</sup> It acts more like equity – it has a lower claim on the company's assets than senior debt (that is, debt sourced from bank loans or via bond issues) and it earns higher returns to compensate the lenders for this higher level of risk.

This debt acts as an additional buffer to absorb losses that would otherwise be borne by senior lenders such as banks or bondholders. It lowers the risk that the senior lenders face, and thus reduces the price that the distributors must pay for senior debt.

Such arrangements may also have tax advantages, as income is effectively passed through to the equity-holders (who in some cases are offshore and not subject to Australian company tax) before tax as interest, rather than after tax as returns to equity holders.

Given the debt's equity-like nature and the fact that it is generally provided by equity-holders in proportion to their equity investments, we consider that its classification as debt is often a tax-effective capital structuring decision rather than representing an arms-length or commercial debt investment.

This implies that the costs of senior debt should be relatively consistent regardless of the related party debt investments'

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<sup>59</sup> Summarised in Australian Energy Regulator (2012b), p 55

<sup>60</sup> Ibid., p 56

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<sup>61</sup> Details of subordinated debt are discussed in the annual reports of the relevant DNSPs and parent companies.

classifications, and that the cost of senior debt represents the actual market cost of debt for the distributors.

### 3.4.2 Our approach

#### Analysis of actual costs of debt

It is important to note that a typical distributor will maintain a portfolio of borrowings, and that the effective cost of debt in a given year will reflect its prevailing costs of debt only to the extent that the portfolio has been refinanced within that year.

Taking a similar approach to that of the Productivity Commission report into electricity network regulation, we have sought to determine the actual costs of debt faced by distributors.<sup>62</sup>

For NSW, Queensland, Victoria and South Australia, we have compared each distributor's determined cost of debt with an estimate of the actual costs of debt that it paid. Where companies have quoted a weighted average interest rate for their borrowings we have used this figure; in other cases we have estimated an average actual cost of debt.

To estimate actual costs of debt we have divided each company's annual finance and/or interest expenses by its average outstanding borrowings for the year. Data have been obtained from the companies' annual reports. (Care should be taken in interpreting the results as this simple average of opening and closing debt balances will not precisely reflect distributors' individual refinancing schedules.)

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<sup>62</sup> Productivity Commission (2012), p 197

Distributors have differing debt maturity profiles and use hedging (e.g. via interest rate forwards and swaps) to minimise their exposure to movements in rates. Our approach recognises that only a portion of each distributor's debt will thus be exposed to the prevailing costs of debt during the regulatory period. A mixture of existing and new debt will contribute to the overall debt expense of each company. Our cost of debt calculation captures the actual debt servicing burden.

We have added a 10-year moving average of the Bloomberg BBB Fair Value Curve in order to estimate the prevailing cost of debt for a company managing a debt portfolio with an average term of ten years.

#### Government debt financing

Distributors in NSW and Queensland source debt funding from their respective state treasury corporations. The treasury corporations are guaranteed by their respective state governments, and thus face very low costs of debt when they borrow on the capital markets. They apply competitive neutrality fees to the loans that they extend to government-owned corporations ('GOCs', such as the distributors) to ensure that the costs of debt borne by the GOCs are equivalent to the costs they would face were they standalone borrowers seeking loans on commercial terms.<sup>63</sup>

We note that there is a mismatch between the timing of the regulatory determination of the cost of debt, which applies for the entire regulatory period, and the calculation of the spreads used in

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<sup>63</sup> The State of Queensland (2009), NSW Treasury (2010)

the competitive neutrality fees. For example, Queensland Treasury Corporation surveys the market quarterly and adjusts their competitive neutrality fees accordingly.<sup>64</sup> In a falling rate environment, this could have the effect of reducing the distributors' effective costs of debt, while not affecting the prevailing determined cost of debt.

### Related party debt

Where distributors' capital structure includes related-party or other subordinated debt, we have estimated overall costs of debt as well as the cost for each form of debt.

### Exclusions

We have not performed an assessment for Tasmania or the ACT due to lack of sufficient, relevant data.

### Determining revenue impacts

We have estimated the potential reduction in revenue that could have occurred had the costs of debt been determined in a manner more closely reflecting the likely financing practices of a benchmark efficient distributor.

We have done this by calculating a 10-year moving average of the 10-year Bloomberg BBB Fair Value Curve at the start of each

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<sup>64</sup> The State of Queensland (2009)

financial year (calendar year for Victorian distributors<sup>65</sup>), and assuming a regulatory model where this figure is used each year to mechanically update the cost of debt in the WACC. The cost of equity has not been modified in this analysis.<sup>66</sup>

This curve is one of several estimates of the market cost of BBB-rated debt provided by financial market practitioners such as Bloomberg, CBA and UBS. We do not recommend that the regulator constrain itself to any particular benchmark; the purpose of this analysis is to demonstrate the likely magnitude of the impact upon allowed revenue were one common example of such an approach to be used.

We note that the BBB curve is likely to over-estimate the appropriate cost of debt for a BBB+ rated borrower, and thus our revenue impact examples are likely to underestimate the potential savings to customers.

The Bloomberg curve was only provided for maturities out to seven years post-2007, so in those years we have calculated a ten-year value by using a simple linear extrapolation of the curve between five and seven years (or seven and eight years where available) out to ten years. Data were not available prior to 2001, so the ten-year moving average is truncated prior to 2011.

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<sup>65</sup> We have estimated the value for 1 January 2013 using the value obtained for 8 November 2012, noting that this may lead to a small discrepancy if debt rates move significantly in December 2012.

<sup>66</sup> We note that this approach effectively averages the risk-free rate component of the curve as well. A regulatory implementation would need to consider a consistent treatment of the risk-free rate as it applies to both debt and equity components of the WACC, as discussed in the AEMC 2012 review of the National Electricity Rules. See AEMC (2012e)

For comparisons with determined costs of debt, we have used the determined cost of debt as reported by the regulator, or where a range was prescribed, the mid-point of that range. We note that this may tend to lower our estimates of the potential revenue reductions, as regulators may tend to use estimates near the higher end of the range to minimise the risk of underinvestment.<sup>67</sup>

### 3.4.3 Detailed analysis by company

For all companies, a 10-year moving average of the Bloomberg BBB curve – a fair and reasonable measure of the cost of debt for a benchmark efficient company – has generally tracked close to or below the allowed cost of debt, never significantly above. In other words, distributors are in general being over-compensated for the cost of their debt.

Figure 3.2 and Figure 3.3 show that for the government-owned companies in New South Wales and Queensland, the allowed cost of debt has been considerably above the effective rates the companies have paid on their debt.

The capital structures of the Victorian distributors differ significantly from one another, so we analyse each independently. Detailed company analyses are contained in Appendix One. For United Energy, Citipower and Powercor, the application of related-party debt adds a layer of complexity that is described in Appendix Two. Overall the allowed costs of debt have tracked close to or above both the effective rates and the Bloomberg BBB cost curve as figure 3.2 shows for Citipower and Powercor.

In South Australia, ETSA's debt structure includes senior debt as well as subordinated related party loans from its owners, Cheung Kong Infrastructure Finance (Australia) P/L and Hong Kong Electric International Finance (Australia) P/L.<sup>68</sup> This debt earned a rate of return of approximately 11.15 per cent,<sup>69</sup> which is greater than the regulated rate of return for equity despite being senior to equity in the company's capital structure.

Given this, we expect such debt to effectively represent an additional equity-like investment from ETSA's parents. As such, its classification as either equity or debt is unlikely to affect the cost of senior debt as long as it is in place to provide financial support to the company.

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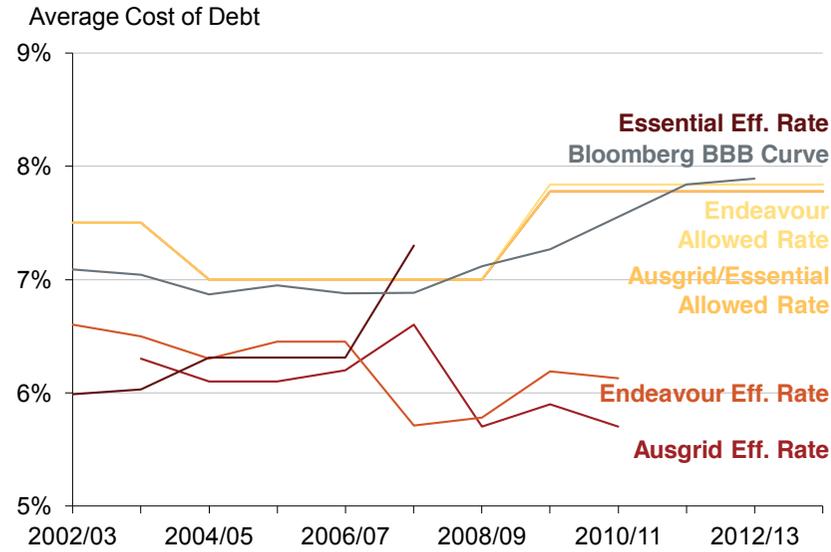
<sup>67</sup> See introductory remarks to the Statement of Regulatory Intent regarding equity market risk premium and beta: Australian Energy Regulator (2009a), p iii

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<sup>68</sup> ETSA Utilities (2012)

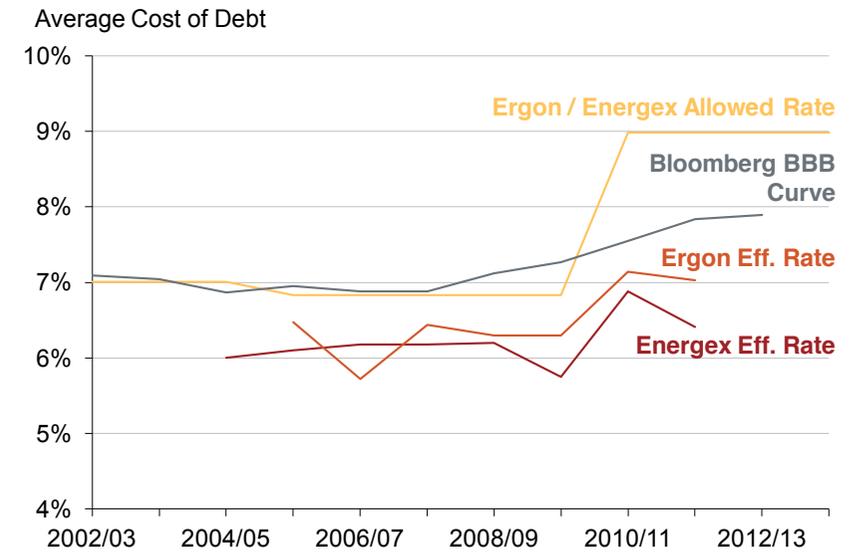
<sup>69</sup> Ibid.

Figure 3.2: NSW distributors' allowed and effective costs of debt



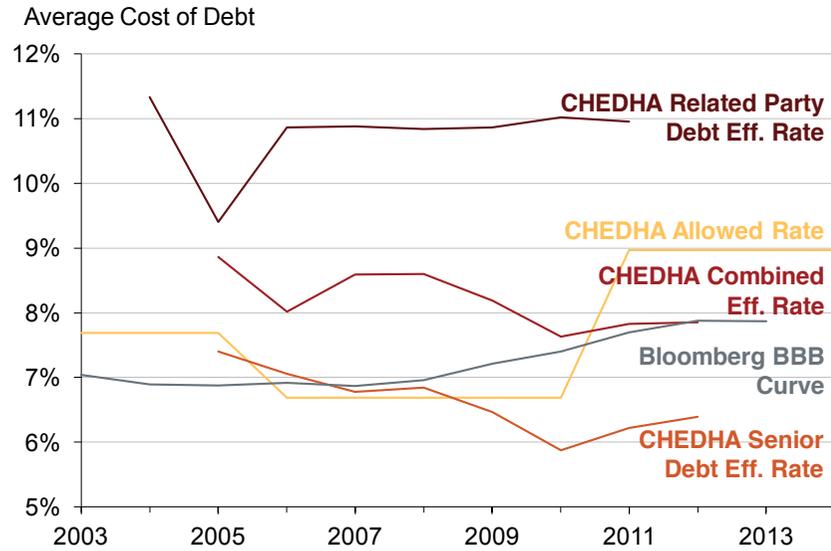
Note: Essential Energy's weighted average interest rates were not provided in annual reports from 2008-09  
 Source: Analysis of data obtained from Bloomberg, company reports Australian Energy Regulator (2012a) and Independent Pricing and Regulatory Tribunal of New South Wales (2012a) and Independent Pricing and Regulatory Tribunal of New South Wales (2004).

Figure 3.3: Queensland distributors' allowed and effective costs of debt



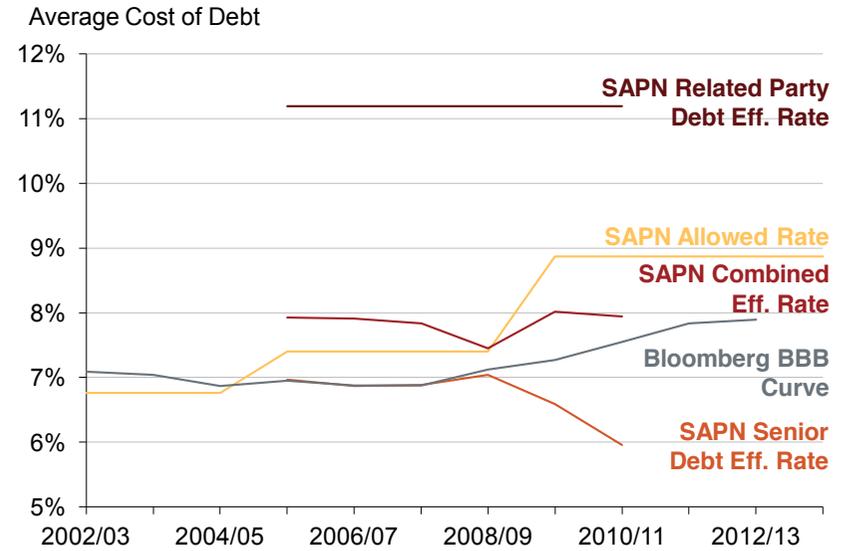
Sources: Analysis of data obtained from Bloomberg; company financial reports, Australian Energy Regulator (2012a) and Queensland Competition Authority (2012c).

**Figure 3.4: Victoria: Citipower and Powercor's allowed and effective costs of debt**



Notes: CHEDHA is the parent company for both Citipower and Powercor;  
 Source: Analysis of data obtained from Bloomberg, company reports, Australian Energy Regulator (2012a) and Essential Services Commission (2006)

**Figure 3.5: South Australia: SA Power Network's allowed and effective costs of debt**



Source: Analysis of data obtained from Bloomberg, company reports, Australian Energy Regulator (2012a) and Essential Services Commission of South Australia (2012b)

### 3.4.4 Potential Revenue Reductions

We have re-calculated the WACCs for each distributor using a cost of debt parameter that is equal to the ten-year moving average of the Bloomberg BBB Fair Value Curve at each year, and have estimated the reductions in revenue that would have occurred had these updated WACCs been used.<sup>70</sup>

**Table 3.2: Potential revenue reductions**

	2009-10	2010-11	2011-12	2012-13
ActewAGL	\$2M	\$1M	\$0M	-
Ausgrid	\$17M	\$11M	-\$3M	-\$7M
Endeavour Energy	\$11M	\$7M	-	-\$1M
Essential Energy	\$10M	\$6M	-\$2M	-\$4M
Energex	-\$20M	\$69M	\$51M	\$57M
Ergon	-\$19M	\$67M	\$46M	\$51M
ETSA	\$35M	\$21M	\$18M	\$18M
Aurora	\$2M	\$0M	-\$2M	\$1M
Citipower	\$6M	\$9M	\$8M	\$9M
Jemena	\$8M	\$10M	\$10M	\$10M
Powercor	\$11M	\$16M	\$15M	\$16M
SP AusNet	\$13M	\$19M	\$19M	\$20M
United Energy	\$7M	\$10M	\$9M	\$10M
<b>Total (2010 \$)</b>	<b>\$84M</b>	<b>\$245M</b>	<b>\$167M</b>	<b>\$180M</b>

*Notes:* Victorian determinations apply to calendar years, e.g. the 2009-10 year column refers to the Victorian year commencing 1 January 2010.

*Source:* Analysis of data obtained from Bloomberg and Australian Energy Regulator (2012a).

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<sup>70</sup> We calculate a moving average at 1 July for the distributors using financial year-based regulatory periods, and 1 January for the distributors using calendar-based regulatory periods.

## 4. Why ownership matters

### 4.1 Summary and recommendations

Many commentators have suggested that electricity prices are influenced by whether distribution companies are publicly or privately owned.<sup>71</sup> They point out that distribution costs have increased by more, and at a faster rate, in government-owned companies than in privately owned companies.

Our analysis tested the hypothesis that government-owned companies are inefficiently investing in their networks. It found that these companies have a larger regulated asset base (or physical infrastructure) per customer, and spend more on capital and operations, than do privately owned companies.

If government-owned companies invested in their infrastructure at the same rate as privately owned companies, customers of government-owned companies could save up to \$640 million per year (in 2010 dollars).

Government-owned companies also tend to spend more per kilometre of line compared to privately owned companies when customer density is taken into account. If government-owned firms spent as much on operational expenses as the average of privately owned firms with equivalent customer density, they would spend about half a billion dollars less each year.

In response, government-owned companies point out that they have been forced to spend more in order to meet increased

reliability standards set by their government owners. They also argue that increased expenditure was needed to replace ageing assets and to build enough infrastructure to meet increasing peak demand.<sup>72</sup>

It is difficult to determine how much capital the companies spent in order to meet new reliability standards, or to separate out capital spent on each of these three objectives. Often they are intertwined.

Nevertheless, governments may be conflicted by their dual roles as company owners and lenders to the same companies. The result is likely to be a level of excessive and inefficient spending on both capital and operations.

In states where distribution companies are publicly owned, governments receive dividends from them. Governments acting as financiers also charge their companies competitive neutrality fees as well as interest on financing. The fees are designed to remove any competitive advantage - including a lower cost of finance - these companies enjoy by virtue of their government ownership. As well, state governments that own distribution companies receive income tax equivalents that would otherwise be paid to the federal government if they were privately owned.

These income streams mean that governments' dual role as owners and financiers can provide incentives for government-

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<sup>71</sup> Mountain and Littlechild (2010), Garnaut (2011), Simshauser, *et al.* (2012)

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<sup>72</sup> Energy Networks Association (2012), p 33

owned companies to spend more on their networks than they need to. Without proper separation between their two roles, governments can be tempted to treat competitive neutrality fees and tax equivalents as windfall revenues.

To discourage government-owned companies from investing more in their infrastructure than is necessary to provide reliable electricity, this report recommends:

- Transferring responsibility for setting reliability standards from government owners to the AEMC. This would remove any potential conflict inherent in government owners setting standards for their own companies
- Improving governance arrangements for government-owned companies to better reflect practices in privately owned companies. Effective 'Chinese walls' between the energy and treasury and finance functions of government may be needed in order to effectively separate governments' roles as both shareholder and financier of distributors. This is likely to reduce some incentives for governments to unduly increase investment in these companies. However, it may not completely eliminate the conflicting government objectives imposed on companies, nor the potential for political interference. Where politically feasible to do so, governments should consider privatising these companies.
- Effective benchmarking by the AER of all proposed expenditure by companies (both government- and privately owned) to determine the efficiency of their

regulatory proposals, in order to eliminate any inefficient spending by distributor companies.<sup>73</sup>

#### Box 4.1 Methodological note

Data were collected from AER and state-based regulatory decisions, as well as regulatory audit reports. All values have been adjusted to June 2010 dollars using the ABS price deflator for Electricity<sup>74</sup> and are presented by financial year. Where companies are regulated by calendar year, their data are presented as representing the previous financial year. For example, 2005 calendar year data are presented as 2004-05 financial year.

The authors acknowledge data provided by Bruce Mountain and Energy Users Association of Australia that enabled them to cross-reference data collected by Grattan researchers.

#### 4.2 Ownership status of electricity distribution companies

Ownership of electricity distribution companies varies across the National Electricity Market (NEM). Queensland, New South Wales and Tasmanian companies are government-owned, whereas Victorian and South Australian distributors are privately owned, having been sold during in the mid to late 1990s. ACT's ActewAGL is part government and part privately owned. We classified ActewAGL as government-owned for the purpose of our analysis.

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<sup>73</sup> This is consistent with AEMC (2012d) which recommended the AER produce an annual benchmarking report of network businesses.

<sup>74</sup> Catalogue 6401.0 Table 15

#### Box 4.2 Data availability makes analysis difficult

Many factors make comparing distribution companies difficult. Across the NEM, networks vary according to:

number and type of customers;

number of customers per kilometre of line (customer density). For example, some companies service CBD areas while others service rural areas. The cost of building and maintaining infrastructure also varies depending on customer density;<sup>75</sup>

forecast and actual energy demand (including both average and peak demand);

weather conditions;

age of assets; and

reliability standards.

This makes benchmarking between companies difficult.<sup>76</sup>

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<sup>75</sup> For example, customers in sparsely populated rural networks may be serviced by a single overhead SWER line which costs less per kilometer of line compared to the cost of one kilometer of line in a CBD, where lines are likely to have greater capacity and be underground. There are also economies of scale gained by supplying customers in a denser network.

<sup>76</sup> Productivity Commission (2012), p 175 notes that no perfect measure is possible but that benchmarking can be a useful tool for specific performance measures.

As well, regulation of distributors has shifted from state-based regulation to national regulation by the Australian Energy Regulator (AER) under the NEM. Consistent data is difficult to gather as reporting requirements and decision-making processes have changed over time.<sup>77</sup>

#### 4.3 Have government-owned companies inefficiently invested in their networks?

Cost to consumers is driven by the size of a company's regulated asset base, capital and operational expenditure, and the return the regulator allows the company to achieve on its investment.

This chapter examines whether government-owned companies have inefficiently invested in, or 'gold plated', their infrastructure. It examines companies' regulated asset bases ('RABs') and capital expenditure. It also examines operational efficiency levels through a comparison of operational expenditure made by government and privately owned companies.

The analysis finds that government-owned companies are inefficiently investing in capital infrastructure. On average, they spend more on their assets, growing their asset base at a faster rate than that of private companies. This remains the case when both the distributor's number of customers and the size of the network (measured by kilometres of line) are taken into account. Government-owned companies also spend more on operations per customer than do privately owned companies. The result is

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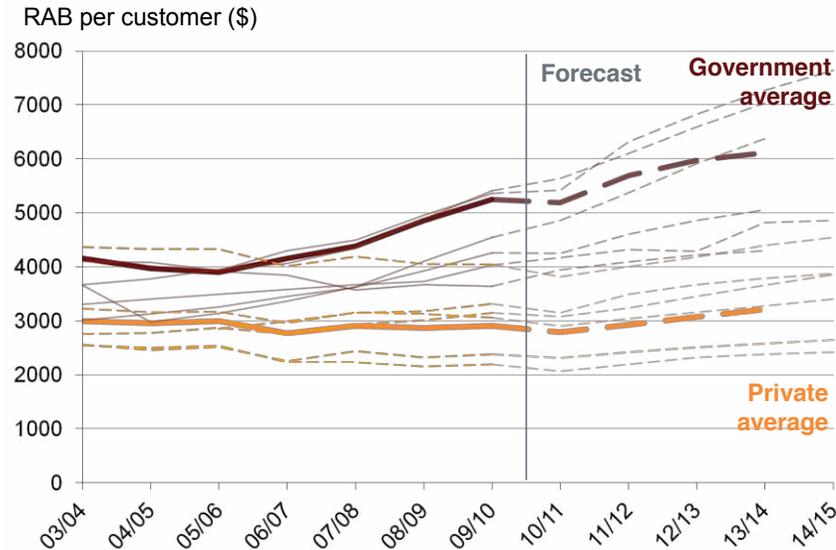
<sup>77</sup> Ibid. p 296. The Productivity Commission's draft recommendation 8.7 recommends that the AER publish all benchmarking input data except where the companies can demonstrate the data is commercially in confidence.

higher cost to consumers in jurisdictions where distributors remain government-owned.

### 4.3.1 The size of companies' regulated asset bases

Figure 4.1 shows the difference between the two kinds of distributors, in terms of size and rate of growth of their asset bases.

Figure 4.1 RAB per customer actual and forecast (\$June 2010)



Sources: Analysis of data obtained from distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>78</sup> and regulatory audit reports.<sup>79</sup>

The RABs per customer of several government-owned companies (Endeavour Energy, Energex, Ergon and Ausgrid) will have increased between 40 and 80 per cent in the ten-year period between 2003-04 and 2013-14. By contrast, the RABs per customer of the Victorian privately owned companies (bar SP AusNet) have remained stable over the same period. Ergon Energy, which services the regional and remote areas of Queensland, is excluded because its size would make the graph difficult to read. Yet it fits the pattern of a government-owned company's asset base being both larger and rising faster than privately owned companies. Its RAB per customer was \$6,200 in 2005-06 and is forecast to nearly double to \$11,390 by 2014-15.<sup>80</sup>

The analysis is consistent with that of the Productivity Commission, which found recently that the RABs of government-owned companies increased much more than those of privately owned companies.<sup>81</sup> The former companies also delivered less network capacity. This is illustrated by the differences, seen in

<sup>78</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2003) and Office of the Tasmanian Economic Regulator (2007)

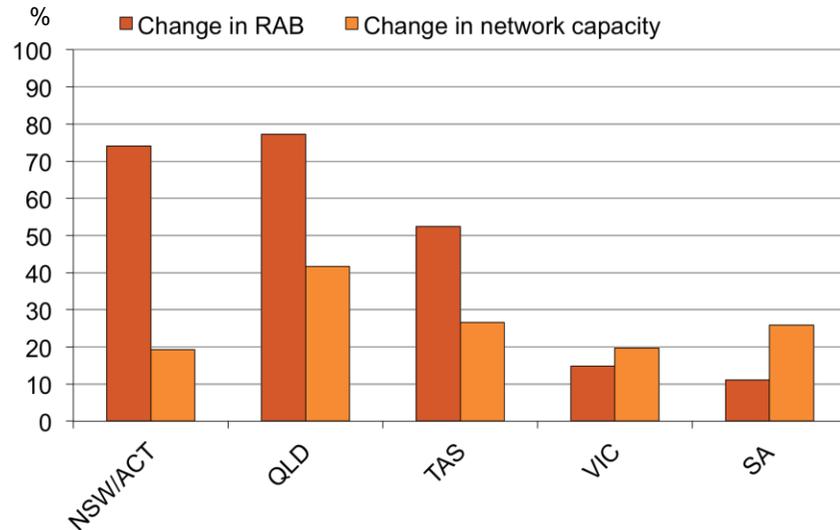
<sup>79</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a)

<sup>80</sup> ActewAGL, Aurora, Ausgrid, Essential and Energy's forecast RAB per customer is based on customer numbers forecast by Grattan researchers using the customer growth rates of the preceding period.

<sup>81</sup> Productivity Commission (2012), p 222

figure 4.2, between the RABs at the beginning of the previous regulatory period and the RABs at the beginning of the current regulatory period compared with the corresponding change in network capacity.

**Figure 4.2 Percentage change in RAB and network capacity for distribution networks**



Note: Network capacity is calculated as the length of network line (km) multiplied by transformer capacity (MVA)

Source: Analysis of data obtained from AER determinations cited in Productivity Commission (2012), p 238.

**Box 4.3: Government-owned companies' inefficient investment in RABs**

Government-owned companies' RABs per customer are higher than those of private companies in 2004-05 before the gap widens from 2005-06 (following a change in government-owned companies' reliability standards). The difference in 2004-05 may be, in part, attributed to inefficient governments' investment in their RAB.<sup>82</sup>

We analysed the difference in government and private companies' RABs in 2004-05, prior to changes in reliability standards.<sup>83</sup> Our analysis found that the additional investment by government-owned companies by 2004-05 is between \$2.1 and \$5.4 billion (in 2010 dollars).<sup>84</sup>

<sup>82</sup> We acknowledge the difficulty in inferring inefficiency solely from the RAB. There are several factors which influence the size of the RAB that are outside the managerial control of companies such as the size of the service area, topology, number of customers and levels of demand. Other factors that may or may not be within the control of the company include the types of assets purchased, the prices paid for assets and the timing of capital expenditure. Ibid., p 239

<sup>83</sup> Reliability standards changed in 2005-06 in New South Wales, 2005-06 in Queensland and 2008 in Tasmania.

<sup>84</sup> This analysis excludes ETSA as no RAB figures are publicly available. This does not bias the analysis, however may lower the degree of accuracy of the stated range.

The lower estimate is calculated on a RAB per customer kilometre basis<sup>85</sup> and the upper estimate is calculated on a RAB per customer basis.<sup>86</sup>

We also tested the difference in RAB between these companies using the Composite Scale Variable (CSV) used by Bruce Mountain.<sup>87</sup> The CSV weighted RAB by companies' kilometres of line (0.5), number of customers (0.25) and Gwh delivered (0.25). Using this metric, the difference of RAB between government and privately owned companies was \$8.7 billion. Given the size of the figure in comparison to the other estimates, we decided to use the more conservative range above.

The additional investment in government-owned companies compared to private companies in 2004-05 translates to increased total revenue for government-owned companies between \$250m and \$640 million per year.<sup>88</sup>

As well, when the number of customers per kilometre of line (or customer density) is taken into account, government-owned companies have much higher RABs per customer compared to privately owned companies.

Our analysis compared RAB per customer against customer density between 2005-06 and 2008-09 (the longest period of comparison possible due to a lack of kilometre-of-line data). Figure 4.3 shows that in 2005-06, most government-owned companies already had a higher RAB per customer compared to privately owned companies, once customer density is taken into account. However, the gap has grown.

Figure 4.4 shows that by 2008-09, government-owned companies had a significantly higher RAB per customer than did privately owned companies. This includes government-owned companies that previously had a similar RAB per customer to privately owned companies such as Endeavour and Ausgrid. For government-owned companies, the RAB per customer decreases as customer density increases. By contrast, the RAB per customer of privately owned companies – already lower in most cases – remains steady regardless of customer density.

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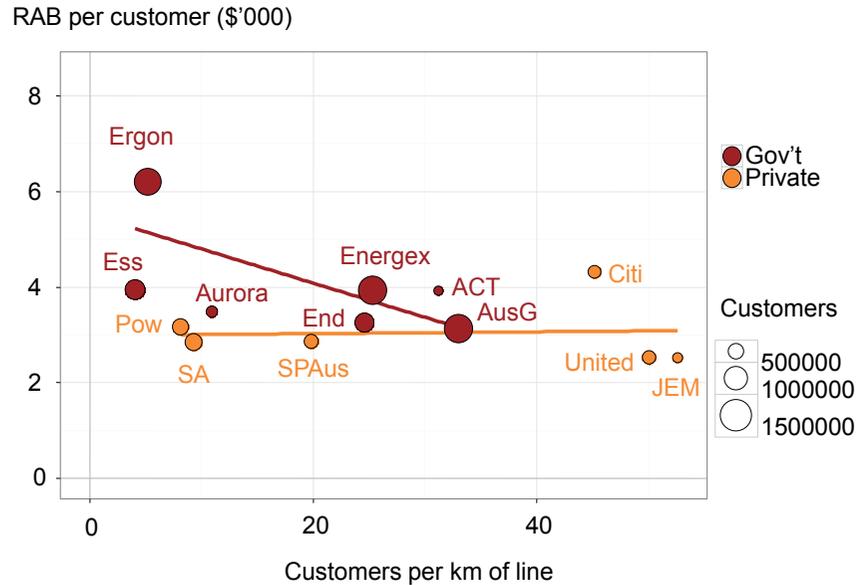
<sup>85</sup> The difference between government and private companies' RAB per customer kilometre, multiplied by the total number of customer kilometres for government-owned companies.

<sup>86</sup> The difference between government- and private companies' RAB per customer, multiplied by the total number of customers of government-owned companies.

<sup>87</sup> Mountain (2011)

<sup>88</sup> This is based on the assumption of a WACC of 9.3 per cent and depreciation of assets with a standard asset life of 40 years.

Figure 4.3: RAB per customer by customer density 2005-06 (\$June 2010)

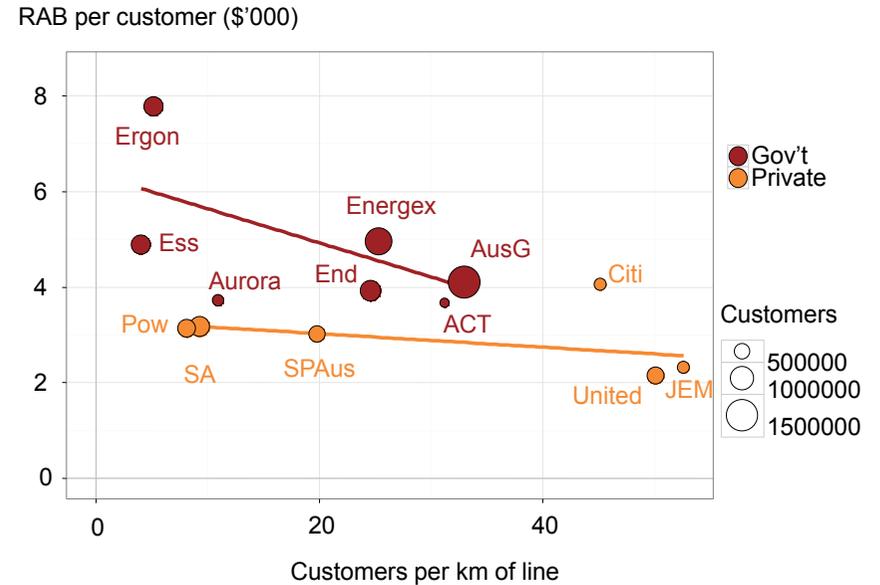


Sources: Analysis of data obtained from distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>89</sup> and regulatory audit reports.<sup>90</sup>

<sup>89</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2003) and Office of the Tasmanian Economic Regulator (2007)

<sup>90</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a).

Figure 4.4: RAB per customer by customer density in 2008-09 (\$June 2010)



Sources: Analysis of data obtained from distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>91</sup> and regulatory audit reports.<sup>92</sup>

<sup>91</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2003) and Office of the Tasmanian Economic Regulator (2007)

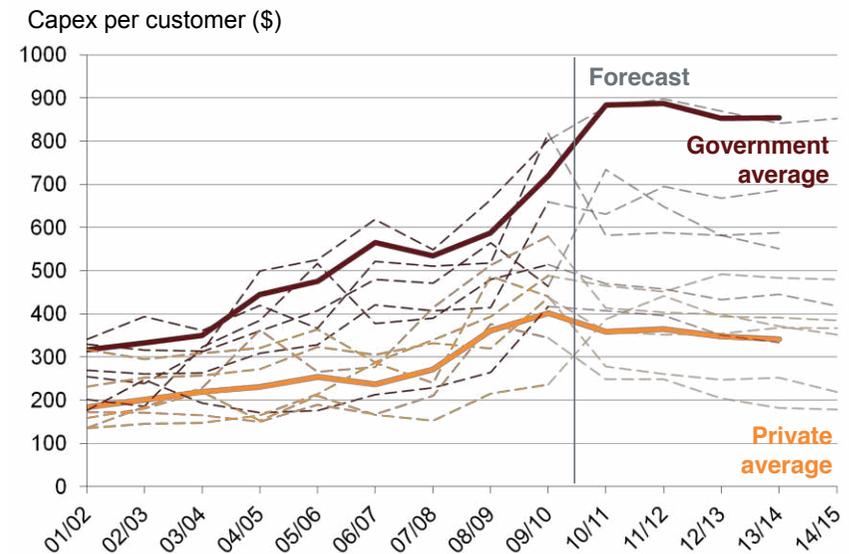
<sup>92</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a).

The only privately owned company that sits significantly above the average private RAB per customer is Victoria's Citipower (RAB per customer of \$4,055 and density of 46 customers per kilometre line). Citipower may be classified as an outlier; it is the only distribution company that solely services a CBD. CBD areas have higher capital infrastructure costs, including requirements to place cables underground, more complex cables and switch systems and higher operational expenditure costs due to difficulty in accessing lines. This compares to other distributors with similar customer density (such as SP AusNet and United Energy) operating in a suburban area where cheaper above-ground poles and wires can be used and more readily accessed for maintenance purposes.

### 4.3.2 Companies' capital expenditure

Over the last 10 years, government-owned companies have invested more capital expenditure (capex) per customer in their network infrastructure than have privately owned companies. The difference largely explains the difference in the regulated asset bases of government-owned and private companies.

**Figure 4.5 Capex per customer (actual and forecast) by ownership (2001-02 to 2014-15) (\$June 2010)**



Sources: Analysis of data obtained from distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>93</sup> and regulatory audit reports.<sup>94</sup>

<sup>93</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2003) and Office of the Tasmanian Economic Regulator (2007)

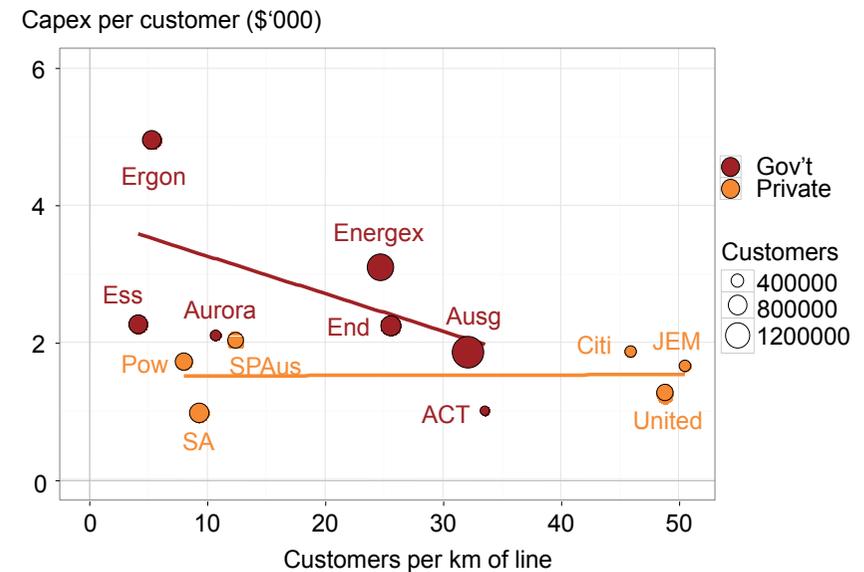
<sup>94</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a)

Figure 4.5 shows that government-owned companies have spent more capex per customer since 2001-02 than privately owned companies and that this trend is forecast to continue throughout the current regulatory period.

As with the earlier graph, Queensland's Ergon Energy has been excluded so as not to distort the graph's scale. Ergon Energy spends significantly more capex per customer than any other company, and the rate of growth of its capex is rapid - from \$550 per customer in 2001-02 to forecast expenditure of \$1,590 per customer in 2014-15.

Figure 4.6 shows that when customer density is considered, government-owned companies also spend more capex per customer than privately owned companies. Our analysis compared total capex per customer in the most recently completed regulatory period for each company.<sup>95</sup> This reduces any 'lumpiness' in capital expenditure that might exist from year to year due to either regulatory incentives or company decisions on the timing of capital expenditure.<sup>96</sup>

Figure 4.6 Capex per customer over 5 years by customer density (\$June 2010)



Sources: Analysis of data obtained from distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>97</sup> and regulatory audit reports.<sup>98</sup>

<sup>95</sup> For Aurora in Tasmania, the period shown is 2004-05 to 2008-09. This enables comparisons over a similar time period given that regulatory periods for Aurora were 2004-2007 and 2008-2012.

<sup>96</sup> Companies have an incentive to delay capex until later in a regulatory period as they receive a return on forecast capex for the duration of the regulatory period, irrespective of when they spend it.

<sup>97</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2003) and Office of the Tasmanian Economic Regulator (2007)

<sup>98</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a)

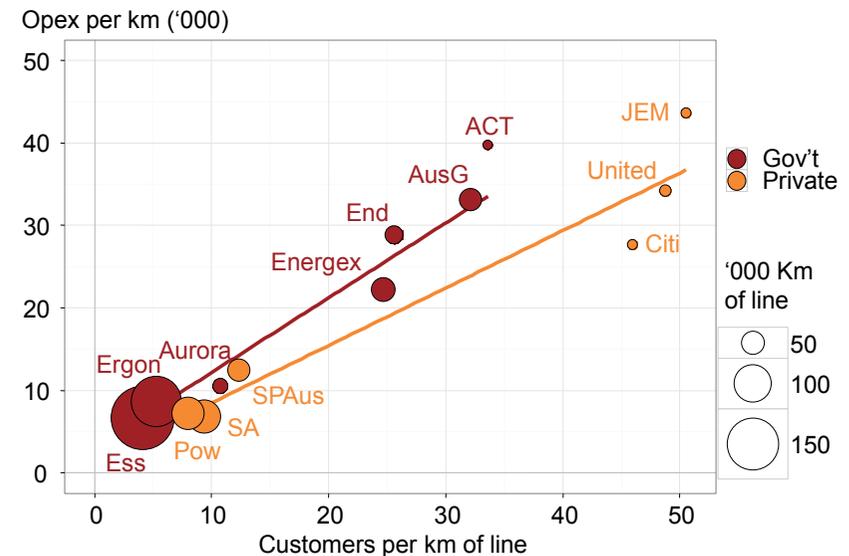
The findings of additional capex spending by government-owned companies is consistent with other analyses, including those of Productivity Commission,<sup>99</sup> Ross Garnaut<sup>100</sup> and Bruce Mountain.<sup>101</sup>

### 4.3.3 Companies' operating expenditure

We compared the operating expenditure (opex) of government-owned and private companies. We assessed opex per kilometre of line against customer density over a four-year period – the only period for which we could access actual opex expenditure per customer and kilometre-of-line data for every company.

Controlling for customer density, government-owned companies tend to spend more on operational expenses than their private counterparts. In fact, no privately owned company spends more on operational expenses than the average government-owned firm with equivalent customer density. If the government-owned firms spent as much on operational expenses as the average of private firms with equivalent customer density, their operational expenditure would fall by about half a billion dollars a year, (in 2010 dollars).<sup>102</sup>

Figure 4.7 Total opex per kilometre line by customer density (2005-06 to 2008-09) (\$June 2010)



Sources: Analysis of data obtained from distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>103</sup> and regulatory audit reports.<sup>104</sup>

<sup>99</sup> Productivity Commission (2012)

<sup>100</sup> Garnaut (2011)

<sup>101</sup> Mountain and Littlechild (2010), Mountain (2012)

<sup>102</sup> A two standard error confidence interval of this estimate is between -0.2 and 1.2 billion in reduced operational expenditures).

<sup>103</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2007) and Office of the Tasmanian Economic Regulator (2003).

<sup>104</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a)

Other factors also suggest that government-owned companies are less efficient in their operational spending than are private companies. They have fewer customers per employee, and spend a higher percentage of the cost of labour, materials and contractors on in-house labour than do private companies.<sup>105</sup>

Other studies that have compared companies on different metrics have produced different conclusions.<sup>106</sup> The choice of metric (and stakeholder viewpoint) can influence findings. We have analysed companies on their opex per kilometre, taking into account their customer density, to account for both the number of customers and the size of the network.

#### 4.4 How government-owned companies explain their higher costs

Government-owned companies attribute their larger and faster-growing asset base and capex per customer to the need to meet increased reliability standards, build additional assets to meet rising peak demand and replace ageing assets.

This report's analysis found that increased reliability standards have indeed caused government-owned companies to increase capital expenditure. However, peak demand has grown at a similar rate in jurisdictions where companies are both government- and privately owned. Rising peak demand is

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<sup>105</sup> Productivity Commission (2012), p 248

<sup>106</sup> Ibid., p224 provides a discussion of other research and analysis conducted in this area including Mountain and Littlechild (2010). Both the AEMC and Productivity Commission note that there is no strong counter-evidence to Bruce Mountain's conclusion that the average privately owned company is more efficient than the average government-owned company. See p 227-228.

therefore unlikely to account for the large differential in capex spending between the two kinds of companies. The claim that ageing assets need to be replaced is difficult to assess due to a lack of available data.

The AER accepts that these three reasons have in part driven increased network costs.<sup>107</sup> However, they do not fully account for the observed levels of increases. AEMO has also suggested that growth in capital expenditure has not all been required by either the age of assets or the growth in demand.<sup>108</sup>

#### 4.4.1 Reliability standards

Government-owned companies have increased both their regulated asset base and capital expenditure in response to the imposition of increased reliability standards.

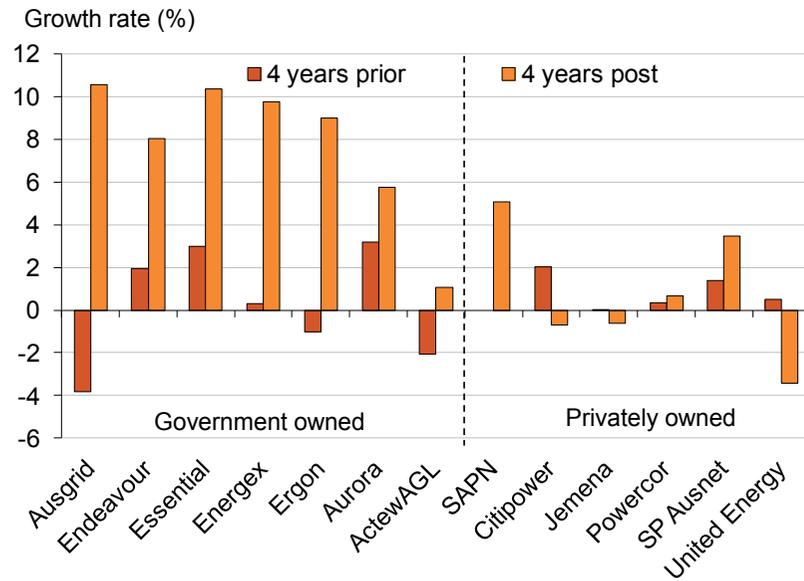
Reliability standards changed in New South Wales in 2005-06, Queensland in 2005-06 and Tasmania in 2008. Changes were only made in states where electricity distribution companies are government-owned.

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<sup>107</sup> Australian Energy Regulator (2011a), p 6

<sup>108</sup> AEMO (2012b), p 42

**Figure 4.8: RAB compound annual growth rate pre and post changes to reliability standards**



Note: no figure is available for privately owned SA Power Networks (SAPN) for the period prior to the change in reliability due to a lack of publicly available RAB data.  
 Source: Analysis of data obtained from regulatory audit reports and distribution determinations

Figure 4.8 shows that government-owned companies’ regulated asset bases grew at a significantly faster rate each year in the four years following a change in reliability standards than they did in the four years before the change.

Prior to a change in reliability standards, Essential and Aurora’s asset base grew fastest, at about 3 per cent each year. Following

the change in reliability standards, all government-owned companies increased their asset base Ausgrid, Essential Energy, Energex and Ergon Energy increased their asset base between 9 and 10.5 per cent *every year* for the following four years.<sup>109</sup>

In contrast, privately owned companies experienced no change in reliability standards and increased their asset base at a much lower rate in the same periods.

The analysis cannot demonstrate that the increased growth in asset bases is solely caused by changed reliability standards in government-owned companies. However, this analysis suggests it has had a large impact.

Chapter 5 examines in more detail the additional cost of meeting higher reliability standards and whether increased standards and expenditure delivered improved reliability.

#### 4.4.2 Peak demand

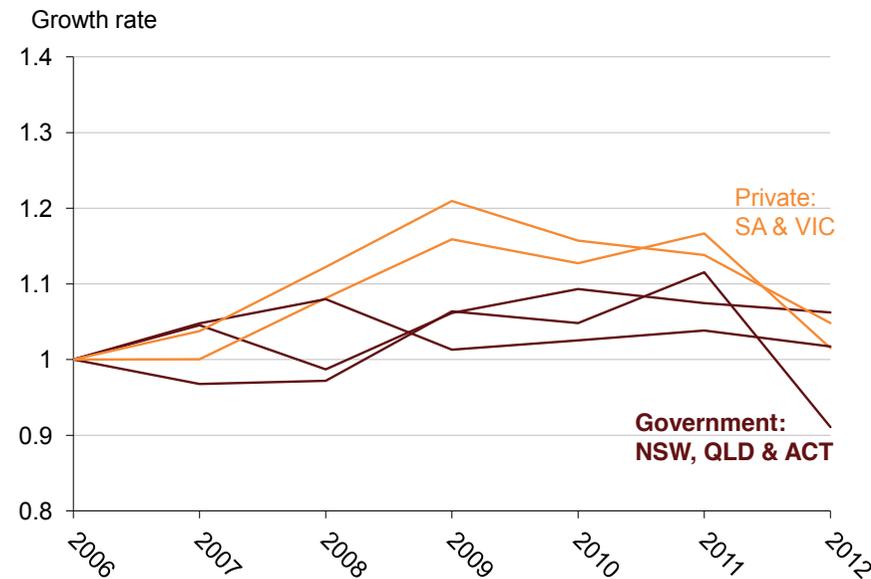
The continual increase in the level of peak demand over the previous two regulatory periods mean that capital expenditure forecasts have also increased.<sup>110</sup>

However peak demand is an issue that affects both government- and privately owned companies. Grattan compared the growth rates of actual peak demand for each state.

<sup>109</sup> Note that the change in Energex and Ergon Energy’s RAB before changes to reliability standards relates to growth rate over 3 years (due to a lack of publicly available data).

<sup>110</sup> Productivity Commission (2012), p 232

**Figure 4.9: States' peak demand growth rates by ownership status (2006 – 2012)**



Source: Analysis of data obtained from AEMO (2012d)

Figure 4.9 shows that peak demand increased slightly faster in states where distribution companies are privately owned compared to those where companies remain government-owned. This suggests that the difference between peak demand growth rates is unlikely to explain the magnitude of difference between the increased capex of government-owned companies and that of privately owned companies.

There is also some qualitative evidence that government-owned companies in Queensland have received higher regulated capex

allowances than are necessary to cope with peak demand. While peak demand is difficult to forecast, an independent review found that Energex and Ergon Energy have consistently over-estimated peak demand.<sup>111</sup>

Across Australia, it is difficult to establish whether capex spent to cope with peak demand has been efficient. Different companies have taken different approaches. AEMO notes that privately owned companies in Victoria have augmented their network at a lower level compared to companies in New South Wales and Queensland.<sup>112</sup> Victoria has used other strategies such as load-shedding control schemes, line-uprating opportunities and the release of additional capacity.<sup>113</sup>

Over time, how companies adjust their capex spending in response to reduced peak demand forecasts may cast light on the respective efficiency levels of government- and privately owned companies. This is discussed in more detail in chapter 6.

#### 4.4.3 Age of assets

Government-owned companies attribute some of their increased capital expenditure to the need to replace ageing assets. In other words, prior underinvestment required additional 'catch up' capital expenditure compared to private companies.

These assertions are difficult to assess as few companies publish detailed information about the age of their capital stock. The

<sup>111</sup> The State of Queensland (2011) p 57

<sup>112</sup> Productivity Commission (2012), p 234

<sup>113</sup> AEMO (2012b), cited in Productivity Commission (2012), p 234

Australian Energy Regulator can now assess the weighted average age of companies' assets through their Post Tax Revenue Model.<sup>114</sup> However, it has only made this assessment once, at the start of the most recent regulatory period for each company. Since there is no assessment of the age of companies' assets before this time, we cannot say to what extent earlier increases in capital expenditure reduced the age profile of companies' assets.

Using the AER's model, Bruce Mountain assessed the average remaining life span of companies' assets at the start of the current regulatory period.<sup>115</sup> He found that government-owned companies have a longer average remaining life span compared to privately owned companies. Because government-owned companies have newer assets, Mountain assumed that privately owned companies would therefore have higher forecast capex for asset replacement in the current regulatory period. Yet contrary to expectations, the forecast replacement capex of government-owned companies is four times that of privately owned companies.

The evidence is clear that government-owned companies spend more capex on asset replacement than do private companies. Yet it is clear whether this is inefficient, or how great the extent of potential inefficiency at these companies is. This is because:

- Replacement capex is a small portion of the replacement value of assets that have reached the end of their lives;

- Standard asset life may be a better indicator of asset replacement for some categories of assets; and
- The timing of replacement capex is a significant factor in determining efficiency of expenditure.<sup>116</sup>

Some qualitative evidence also indicates that companies must sometimes increase capital expenditure in order to catch up on previous underinvestment. A 2004 review of Queensland's electricity supply, commonly known as the Somerville Report, noted that since 1989 Energex had used planning methodology that promoted increased asset utilisation, reducing spare network capacity. Somerville estimated that this reduced spending on the network by approximately \$41 billion over 10 to 12 years.<sup>117</sup> However, saving all that money was not prudent for the most effective running of the network. New investment was required.

#### 4.5 Why government owners have extra incentives to invest in distribution companies

While government-owned companies' capex increased with the introduction of higher reliability standards, it is unlikely that the combination of increased reliability standards, peak demand and the need to replace ageing assets account for the entire difference in spending between government- and privately owned companies.

It is difficult to prove that government-owned companies are 'gold plating' their assets. And since government-owned and privately

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<sup>114</sup> AER's replacement capex or 'repex' model.

<sup>115</sup> Mountain (2011); 2009-10 in New South Wales and 2010-11 for Queensland and Victoria.

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<sup>116</sup> Productivity Commission (2012), p 241

<sup>117</sup> The State of Queensland (2004), p 13

owned companies face similar costs of debt, they have similar incentives to invest in their networks. However, the government owners of distributors have extra incentives to increase investment in their networks because they receive revenue from their distributors in the form of dividends, competitive neutrality fees and income tax equivalents.

Government owners therefore have conflicting roles as both shareholder and financier of the companies. As a shareholder the government should seek to minimise expenditure in order to maximise dividend returns. But as financier, it has an incentive to increase spending in these networks, as it brings higher returns from financing costs. In addition, higher spending on the network produces higher company revenues and therefore increased income tax equivalents paid to the state government owner.

Finally, government owners face political pressures that private companies do not. These include procurement and employment policies and, above all, the pressure to provide reliable electricity. This creates the potential for political intervention in the operations of government-owned companies. We now consider in turn each of the differences between government- and privately owned companies.

#### 4.5.1 Cost of debt and competitive neutrality fees

Government-owned and private companies have similar incentives to spend efficient levels of capex. The application of competitive neutrality fees (CNFs) to government-owned companies ensures they face a similar cost of debt to that of private companies. The fees are designed to minimise any competitive advantage that government-owned companies would

receive from borrowing debt at a lower rate. They are also designed to compensate governments for the additional risk they bear in lending to companies with lower credit ratings than government.

These fees therefore provide a benefit to the government owners rather than to the companies themselves. The government owners retain the competitive neutrality fee: the difference between interest recovered to service its debt and the rate at which it lends the money to the company.

The Productivity Commission has stated that there appears to be a difference in borrowing costs between government-owned and private companies even after the application of CNFs.<sup>118</sup> However, the Productivity Commission also notes that it is a complex issue, with large differences between businesses.<sup>119</sup> Privately owned companies can have complex debt financing arrangements including high-cost related party debt. This raises the average cost of capital for privately owned companies, making comparisons with government-owned companies difficult.

The analysis in chapter 3 finds that CNFs charged by state governments are relatively accurate in matching the actual cost of debt for BBB+ rated companies. However, differences between the effective cost of debt of government-owned and private companies may arise when debt costs are changing. This is because the methodology to compute CNFs is more responsive to changes in finance markets. Governments use quarterly benchmarks to readjust CNFs. By contrast, privately owned

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<sup>118</sup> Productivity Commission (2012), p 203

<sup>119</sup> Ibid.

companies' debt is locked in for longer periods (typically five to ten year bonds), so their actual cost of debt is slower to reflect movements in debt costs.

#### **4.5.2 Government's conflicting roles as both shareholder and financier**

Unlike privately owned companies, government-owned companies receive equity and debt funding from the one source. This creates conflicting objectives for government:

- As shareholders, governments receive dividends, and so should seek to minimise cost in order to maximise dividend returns.
- As financiers, governments receive return on debt in interest payments to the Treasury, as well as competitive neutrality fees.

How governments treat these fees matters. They should treat them as a bank would in lending money to companies with risk profiles greater than their own.

Governments also receive income tax equivalents from government-owned companies. Instead of paying company tax to the federal government, government-owned companies pay an income tax equivalent to their state government. Income tax equivalents are an incentive for governments to influence the amount of capital the companies spend on the networks. Increased capex by companies leads to increased revenues and therefore higher income tax equivalents paid to the government.

While governments cannot directly influence the amount of capex individual companies spend on the networks, they have an incentive to influence the rules or requirements these companies must meet. This can indirectly affect the level of capex these companies spend.

#### **4.5.3 Government always has political objectives**

Government owners have political and non-commercial objectives that privately owned companies do not have. These can lead to a government-owned company spending extra on capital and operations in pursuit of these objectives.

We are not suggesting that state governments deliberately impose these obligations in order to increase revenue from government-owned companies. Nevertheless, the incentives exist. These additional requirements can conflict with purely commercial objectives.

#### **Ability to set reliability standards and licence conditions**

Government owners are responsible for setting reliability standards and licence conditions. Governments in New South Wales, Queensland and Tasmania have all increased reliability standards and planning criteria as discussed in chapter 5.

The AEMC is currently reviewing whether a nationally consistent framework for reliability standards should be set. Its draft recommendation is that the AEMC should establish a nationally

consistent framework for reliability standards under which states can set specific targets.<sup>120</sup>

### Imposition of government requirements that conflict with commercial objectives

The Productivity Commission outlined the following areas in which governments can impose higher requirements on government-owned distributors:

- Additional objectives and non-commercial directives

In New South Wales, government-owned companies must give equal weight to commercial success, social responsibility, ecological sustainability, and responsibility for regional development and decentralisation. The Queensland Government retains the ability to make non-commercial directives. In Tasmania, companies face tensions between obligations to act commercially and broader policy objectives such as the desire to reduce the impact on cost of living for customers or to retain members of the local workforce.<sup>121</sup>

- Procurement policies

New South Wales and Queensland companies are required to follow government procurement policies that encourage local procurement, even when that leads to increased costs.<sup>122</sup>

- Employment policies

Employment policies for state-owned companies appear to produce higher wages than those at private companies, and provide greater protection for workers from structural change.<sup>123</sup>

- Sponsorships

There is evidence that government-owned companies have provided community support and sponsorships far greater than have privately owned companies.<sup>124</sup>

#### 4.5.4 The potential for political interference

The running of government-owned companies should be left to its board of management and executives to avoid perceptions of political interference. Yet the Productivity Commission notes recent examples of the New South Wales, Queensland and Tasmanian governments directing their companies to comply with government procurement plans, and not to recover revenues as allowed by Australian Competition Tribunal decisions.<sup>125</sup>

The Productivity Commission also notes that governments influence capex spending. In recent years, the result has been increased and probably excessive expenditure, but previously some companies may have spent less than was desirable. The

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<sup>120</sup> AEMC (2012b)

<sup>121</sup> Productivity Commission (2012), 257-259

<sup>122</sup> Ibid., p 260

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<sup>123</sup> Ibid., p 261

<sup>124</sup> Ibid., p 262

<sup>125</sup> Ibid., p 263

cycle of under and over expenditure is more likely to reflect political rather than economic considerations.<sup>126</sup>

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<sup>126</sup> Ibid., p 263

## 5. Reliability and cost: restoring the balance

### 5.1 Summary and recommendations

Regulators face a difficult challenge in setting reliability standards; how to ensure that adequate standards are maintained, while also ensuring that customers receive value for money from their electricity networks.

Empirical evidence suggests that the regulated reliability standards in some states have imposed high costs on consumers. Unnecessarily high levels of expenditure in state-based systems suggest the need to review the current arrangements.

This report identifies several reasons why state governments should not set reliability standards. Above all, political factors may prevent a state government from setting standards that maximise the long-term interests of consumers.

As well, the use of different regulatory systems makes it difficult to compare the reliability performance of networks operating in different states. Adopting a national framework would drive accountability by increasing transparency and encouraging benchmarking across the NEM. Reliability standards would be set by a national body such as the AER, rather than state-based regulators.

The focus of national regulation appears to have shifted too far towards ensuring high levels of reliability at the expense of consumers receiving value for money from electricity distribution. This is most evident in states that impose 'deterministic' planning

standards – minimum average standards of reliability that do not consider whether the benefit of higher reliability outweighs the cost to consumers. This report recommends adopting 'probabilistic' standards, consistent with the framework used in Victoria, to restore the balance between reliability and customer value.

These recommendations advocate improving current regulatory arrangements by:

- Establishing a national framework for setting reliability standards.
- Applying a cost-benefit approach to capital expenditure decisions to improve reliability. The model used in Victoria would provide a suitable foundation for a national model.

A national framework for reliability standards would improve transparency and enable benchmarking across regions of the NEM.

### 5.2 Relating reliability standards to electricity prices

#### 5.2.1 Measuring 'reliability'

The 'reliability' of a distribution network is measured in terms of power outages that customers experience as the result of network failures. Reliability is typically assessed using two metrics:

- The *duration* of all outages that an average distribution customer experiences in a year.
- The *number* of outages that the average customer experiences in a year.

These two measures are related; the duration of outages is the number of outages multiplied by the average time per outage. For this reason, this analysis focuses on the average unplanned outage duration per customer.

### 5.2.2 Current regulatory arrangements

Reliability standards are a key component of the regulatory framework for electricity distribution networks. The AER is responsible for setting the overall regulatory framework.

Under this framework, the major component of revenue a distribution business can earn each year is determined as a percentage of the company's assets (the 'Regulated Asset Base'). Capital expenditure by the business adds to the value of assets, thereby increasing the regulated revenue the business is permitted to earn.

The regulation of reliability standards is split between state and national bodies. Under current arrangements, state governments set average reliability standards in all states except Victoria, where targets are set by the AER. Standards typically impose minimum average service levels and encourage businesses to meet them through financial incentives. In New South Wales, a company must meet reliability standards in order to satisfy its licensing conditions.

As well as reliability targets, some states also impose network planning requirements on distribution companies. In these cases, governments may require the business to build more capacity if rising demand for energy means the network is not equipped to cope with the failure of one or more network components.

The New South Wales Government currently imposes network planning requirements and the Queensland Government provides planning recommendations. Where state governments do not set standards, as in Victoria, distributors undertake network planning activities in the course of their business planning processes.

Critically, the frameworks for setting both reliability standards and network planning requirements differ significantly between states. This has several drawbacks:

- It makes interstate comparisons of reliability performance difficult and therefore limits the extent to which benchmarking can be used to determine the efficiency of reliability improvements.
- Some regulatory structures appear to apply more effective incentives than others. This suggests arrangements in some states could be improved by moving to a more consistent model.

### 5.2.3 Decisions to build new capacity

Different approaches to network planning are applied within different NEM jurisdictions. Broadly, the approaches can be categorised as either 'deterministic' or 'probabilistic'.

A 'deterministic' approach typically operates in conjunction with government-imposed network planning guidelines, such as the standards imposed in New South Wales or the recommended standards in Queensland. Deterministic standards seek to ensure that the network can cope with the failure of one or more network components at any time. Infrastructure investments are made on the assumption that a network failure will always occur during a period of maximum demand. Further, deterministic standards do not consider whether the benefit of higher reliability is worth the cost of the investment.

By contrast, a 'probabilistic' approach to network planning assesses the likelihood that a component failure will coincide with a period of peak demand. While the deterministic approach takes a conservative view of how much energy could be lost during an outage, the probabilistic approach attempts to estimate expected losses.

Under a probabilistic approach, identifying a reliability issue is not enough on its own to justify capital investment. Once a reliability issue is identified, the distributor will calculate the expected cost of an outage by taking the product of the expected energy lost and the 'Value of Customer Reliability' (VCR). The VCR is a dollar amount representing the cost incurred by the average customer during an outage. The cost of the outage is compared to the cost of building new capacity and the project is only undertaken if it is determined to be cost-effective.

#### 5.2.4 Restoring the balance

Probabilistic planning is a key component in restoring the balance between network reliability and giving electricity customers value

for money because it gives unbiased estimates of expected energy losses and includes an economic efficiency test.

In addition, distributors must have the flexibility and incentives to consider a range of options for solving reliability issues. Network planning requirements often allow distributors to respond to rising demand forecasts in only one way: by investing in the network. They do not allow companies to adopt more innovative approaches. An example of the value of encouraging innovation has emerged recently in Victoria, where distribution businesses improved reliability by altering the configuration of assets in their networks, rather than building more infrastructure.

#### 5.3 An argument for national consistency

There are several reasons why it would be appropriate to move to a national framework for setting reliability standards:

- Empirical evidence suggests current arrangements have imposed unnecessarily high costs on consumers in some states.
- State governments may face conflicts in setting reliability standards. They may be pressured to respond to short-term political incentives or, in states where they own the distribution networks, be tempted to raise reliability standards to increase dividends.
- Adopting a national framework would increase transparency, encourage benchmarking and improve efficiency.

### 5.3.1 The high cost of state-based regulation

Over the last decade, reliability standards have been increased in Queensland (2005),<sup>127</sup> New South Wales (2005)<sup>128</sup> and Tasmania (2008).<sup>129</sup> Empirical evidence suggests that the effect is unnecessarily high costs on consumers. Box 5.1 provides a case study of how recent spending on reliability improvements in New South Wales imposed a net cost of \$285 million on energy users between 2006 and 2009.

#### Box 5.1: Case study on the high cost of reliability in New South Wales

In 2005, the New South Wales Government set more stringent reliability standards for distribution companies. To meet these requirements, the New South Wales regulator, IPART, allowed distribution businesses to increase capital and operating expenditure.

As shown in Table 5.1, these stricter reliability standards led to an additional \$1,342 million in capital expenditure and \$172.8 million in operating expenditure. This increased costs to New South Wales electricity consumers by \$339 million over three years.<sup>130</sup>

**Table 5.1: Recent costs incurred to improve New South Wales reliability standards (\$ million)**

Expenditure Type	2006-07	2007-08	2008-09	Total
Capital Expenditure	404.0	412.6	510.7	1 341.7
Operating Expenditure	52.1	57.2	60.2	172.8
Annual Cost to Customers	74.4	110.7	154	339.1

Following the introduction of higher reliability standards, the average New South Wales customer experienced an average of two minutes less in outage time per year.<sup>131</sup> Networks delivered 570 megawatt hours of energy that would otherwise have been lost.<sup>132</sup>

The average household may use around 3 kilowatts of power during a peak period. AEMC modelling has found that the average New South Wales customer places a value of \$95 per kilowatt hour on reliability<sup>133</sup> – an outage value of \$285 per hour for each household. In total, customers would place a value of \$54 million on avoiding 570 megawatt hours of outages.

New South Wales consumers spent \$339 million to avoid outages valued at \$54 million – that means they spent \$285 million that might have been saved.

<sup>127</sup> Queensland Competition Authority (2007), p 4

<sup>128</sup> Independent Pricing and Regulatory Tribunal of New South Wales (2006), p 2

<sup>129</sup> Office of the Tasmanian Economic Regulator (2012)

<sup>130</sup> Independent Pricing and Regulatory Tribunal of New South Wales (2006) p 5

<sup>131</sup> Ausgrid (2012), Independent Pricing and Regulatory Tribunal of New South Wales (2008); Endeavour Energy (2011); *ibid.*; Energy (2011)

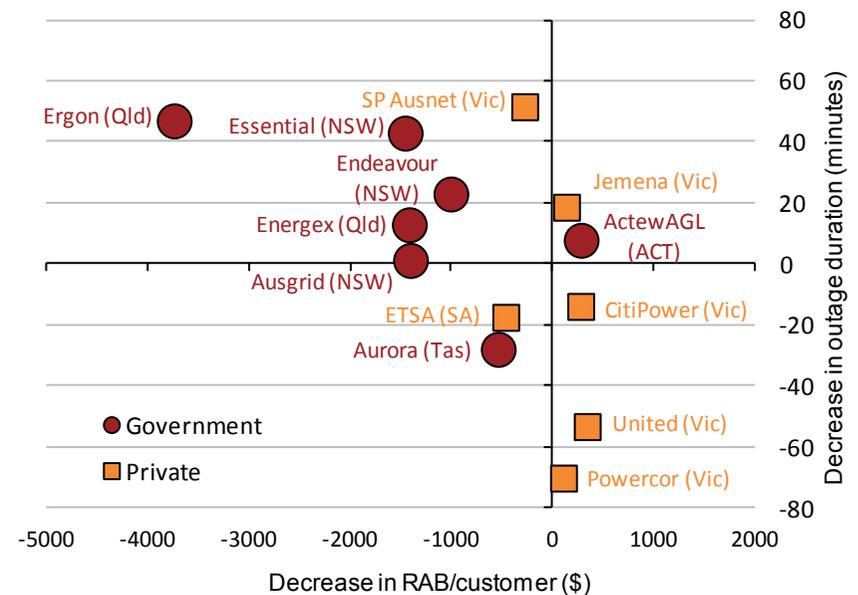
<sup>132</sup> Grattan analysis of AEMC (2012h)

<sup>133</sup> *Ibid.* We note that this value includes multiple customer segments and commercial customers are likely to value reliability more highly than households.

There is limited evidence that recent investments in reliability have achieved efficient improvements. Figure 5.1 illustrates how distributors' investments in the network compared with normalised reliability improvements from 2005 to 2010. The figure compares the total change in each company's Regulated Asset Base per customer to the change in the total average outage duration. While this analysis cannot be used to draw conclusions about the cost-benefit trade-off for investments in particular businesses, it does highlight two key issues:

- In states where governments set reliability targets, there was a large increase in the value of regulated assets per customer.
- Despite this large expenditure, there is no compelling evidence that reliability standards in these states have dramatically improved, relative to networks that have spent less. Whether or not these investments provide a net benefit to consumers, in New South Wales and Queensland they have not delivered reliability improvements efficiently, relative to other states.

Figure 5.1: Improvements in distributors' reliability performance relative to change in asset value: 2005-06 to 2010-11



Sources: Analysis of distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>134</sup> and regulatory audit reports.<sup>135</sup>

<sup>134</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2003) and Office of the Tasmanian Economic Regulator (2007)

<sup>135</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a)

### 5.3.2 Problems with state-based standard-setting

Authority to set reliability standards should be transferred from state governments to a separate, independent national body such as the AER. Evidence suggests that state-based regulations aimed at improving reliability have not set standards at an economically efficient level.

In the past, a number of state governments appear to have increased reliability standards in response to public perceptions of poor service. In 2004, following a series of power outages that resulted from extreme storms and hot weather events, the Queensland Government initiated a review of reliability standards.<sup>136</sup> Similarly, New South Wales introduced more stringent standards in 2005 following extreme weather.

In politically-charged circumstances, there is pressure for reliability measures to be implemented without adequate consideration of whether the investment is economically efficient. This risk is particularly pronounced in New South Wales and Queensland, which use deterministic reliability standards that do not explicitly incorporate a cost-benefit assessment.

The savings available through a more economically efficient decision making process have been highlighted by AEMO. A 2012 report suggests that around \$185 million could be saved by deferring a number of planned distribution projects by one year. These savings would be spread across New South Wales (\$95 million), Queensland (\$75 million), South Australia (\$12 million),

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<sup>136</sup> The State of Queensland (2004)

Tasmania (\$3 million) and the Australian Capital Territory (\$1 million).<sup>137</sup>

An additional conflict exists in New South Wales and Queensland, where state governments both own distribution businesses and set reliability targets. A state government that owns a distributor may have an incentive to lift reliability standards. This would drive a higher allowance for capital expenditure by distributors, resulting in higher regulated revenues and higher costs for the consumer.

Transferring power to an independent federal agency reduces the politicisation of reliability standards and limits potential conflicts where state governments also own distribution networks. A national government body such as the AER has more scope than state governments to be objective in setting reliability standards to promote efficient investment.

### 5.3.3 Benchmarking to drive performance

The use of different regulatory systems makes it difficult to compare the reliability performance of networks operating in different parts of the NEM. Adopting a national framework would drive accountability by increasing transparency and encouraging benchmarking.

This recommendation is consistent with findings in the AEMC's recent Final Position Paper regarding rule changes for the national electricity network.<sup>138</sup> The paper described benchmarking

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<sup>137</sup> AEMO (2012a), these values were obtained by applying the weighted average cost of capital to the capital cost of distribution projects in each state for one year, consistent with AEMO's approach.

<sup>138</sup> AEMC (2012d), p 9

as “a critical exercise in assessing the efficiency of a ... [network service provider]”.<sup>139</sup>

#### 5.4 A national approach to reliability standards

This report recommends that a national framework for reliability standards:

- Assess the costs and benefits arising from new investment in the network.
- Focus on output measures of network performance, such as the frequency or aggregate duration of unplanned outages.

##### 5.4.1 Guidelines for a national framework

In setting reliability standards, regulators need to determine appropriate targets and ensure businesses have incentives to meet them. Distributors should also be encouraged to meet reliability targets through the most economically efficient approach.

A national framework for distribution reliability planning should adopt a probabilistic approach that takes account of expected energy lost during a distribution network outage. It should also employ a cost-benefit framework to evaluate proposed network augmentations. This cost-benefit assessment would be critical in determining whether an augmentation would be undertaken.

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<sup>139</sup> Ibid., p vii

In practical terms, we expect that this outcome would be achieved by removing centralised network planning frameworks and allowing distribution networks to undertake their own reliability planning activities. Regulation would be based on reliability performance outputs, such as the average outage duration per customer, with financial rewards and penalties for good and bad performance. Regulatory structures such as Service Target Performance Incentive Schemes, which are in the process of being implemented across the NEM, provide a suitable model for structuring incentives.<sup>140</sup>

Ensuring that incentives are based on measures such as the duration and frequency of outputs has a further advantage over network planning regulations. Basing incentives on outputs allows networks maximum flexibility to determine how to meet network constraints. It encourages distributors to consider innovative approaches to improve reliability and incentivises them to select the most economically efficient approaches. For example, a company might find it more economically efficient to manage peak demand in a section of the network, rather than expanding the network capacity by building new infrastructure.

##### 5.4.2 Practical requirements for a national framework

There are several steps in implementing a probabilistic reliability framework:<sup>141</sup>

- First, a reliability issue is identified within a section of the network.

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<sup>140</sup> AEMC (2012i), p 6

<sup>141</sup> Ibid. p 81

- The expected energy that would be lost as a result of an outage is calculated.
- The expected energy that would be lost during an outage is multiplied by the VCR, which measures the dollar value customers place on each megawatt hour of energy lost due to an unplanned outage. This gives the total expected cost of an outage.
- The expected cost of the outage is compared to the cost of improving reliability. Reliability improvements are undertaken where they offer a net positive value.

Where this approach has been implemented, some concerns have been raised about the appropriateness of VCR estimates. Concerns regarding the VCR include difficulties in collecting and maintaining accurate data, and the need to take into account community expectations that may extend beyond economic factors. While we are mindful of these issues, the high cost of deterministic network planning suggests that a cost-benefit approach could deliver significant value to consumers even if a conservative approach was taken to determine the VCR.

The probabilistic approach depends on distributors having access to accurate data concerning their networks. Of key importance are accurate information about the VCR, and tools and data to model the impact of failure in the network. As a first step to implementing these recommendations, policy makers should initiate this analysis.

Box 5.2 uses the example of a recent AEMC report into reliability standards in New South Wales to highlight how this approach

could be used to improve the economic evaluation of projects in that state.

#### **Box 5.2: How reliability standards are driving costs in New South Wales**

At the direction of the Standing Council on Energy and Resources, the AEMC undertook a review of the stricter design planning specifications and reliability standards imposed on New South Wales distributors in 2005. They reported their conclusions in August 2012.<sup>142</sup>

The review made a quantitative cost-benefit assessment that compared the costs of meeting higher reliability standards with the benefit to consumers of higher reliability. The AEMC asked the electricity distributors to quantify the change in capital expenditure that would flow from four scenarios. Three scenarios considered lowering reliability and reducing costs and one considered raising reliability and increasing costs. The scenarios were benchmarked against existing reliability arrangements.

Changes in expenditure under each scenario were translated into a change in the energy delivered to customers. The value of reliability to customers (VCR) was calculated by a survey of New South Wales customers to determine the value they place on reliability to a similar quantification previously undertaken in Victoria.

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<sup>142</sup> AEMC (2012h)

Each of the scenarios was modelled over five and 15-year future timeframes, since it can take several years for changes in expenditure to lead to changes in reliability.

As the results in Table 5.2 indicate, for all scenarios and over both time periods, the costs of increasing reliability would outweigh the benefits delivered to customers.

**Table 5.2: Comparison of reliability scenario cost and benefit impacts for New South Wales**

Reliability change	Timeframe (years)	Project cost (\$ m)	Value to customers (\$ m)	Net value to customers (\$ m)
Modest reduction	5	- 118	- 9	+ 109
	15	- 275	- 47	+ 228
Large reduction	5	- 328	- 83	+ 245
	15	- 1,049	- 404	+ 645
Extreme reduction	5	- 453	- 120	+ 333
	15	- 1,321	- 516	+ 805
Reliability improvement	5	+ 495	+ 123	- 372
	15	+ 1,011	+ 306	- 705

Source: AEMC (2012h)

The AEMC is appropriately cautious in drawing prescriptive conclusions regarding appropriate reliability standards from these results. However, they do provide powerful evidence that changes in setting of reliability standards in New South Wales would deliver net benefits to consumers.

This report recommends that the incentives used to drive reliability performance in each state should allow for interstate variations in the VCR. For example, state-based assessments of VCR may allow for differences in the mix of customer types or different perceptions of the value of reliability. However, targets would be set through a consistent national approach and, while states' individual characteristics would be taken into account, final determinations would be made by the AER.

These recommendations do not necessarily assume that regulatory arrangements in Victoria ensure that network investments are fully efficient. However, the use of a cost-benefit test is central to ensuring that customers receive value for money from network services. If this approach was adopted nationally using consistent methodology, benchmarking across regions could be expected to drive efficiency gains in all regions, including Victoria.

## 6. The regulatory process needs serious work

### 6.1 Summary and recommendations

The move to economic regulation of distributors by the AER has created common principles across jurisdictions. However, reviews by various bodies, including by the AER itself, suggest that in practice the change has largely favoured distributors and is likely to produce higher costs than if the approach recommended in this report were adopted. In particular, the current process has allowed companies to spend capital above the amount allowed within a regulatory period and then have that amount included in their asset base, without scrutiny as to whether the expenditure was justified. The larger its asset base, the bigger the return the company is allowed to achieve through the prices it imposes on its customers.

Further, a five-year regulatory cycle is simply unable to respond to changing circumstances in the market in the way that would occur in a non-regulated competitive market scenario. Yet there are ways to address this problem.

This report recommends that:

- The regulatory process needs to be made more responsive to changing market conditions. This would require the distribution companies to update their capital forecasts on an annual basis in response to the annual update of maximum demand forecasts as published by AEMO.

- Expenditure above approved levels, as adjusted by the above, should be subject to a prudent investment test.
- The AER should be explicitly empowered and directed to go beyond merely responding to investment proposals from distributors, and to consider broad, efficient criteria in assessing the reasonableness of a distributor's expenditure.

It is likely that these changes would have avoided unjustified capital expenditure in the last five years by around \$3.6 billion. Over the next five years they could reduce future excessive capital by up to \$5.9 billion. This would deliver \$680 million per annum on average to consumers in lower electricity costs.

### 6.2 Capital spending above regulatory allowances

All government-owned companies have consistently spent more than their capex allowances in the previous two regulatory periods.<sup>143</sup> The AER estimates that capital expenditure spent in excess of regulated allowances has contributed to approximately 25 per cent of the rise in electricity prices.<sup>144</sup>

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<sup>143</sup> While all states do not have the exactly the same regulatory periods, many align closely:

NSW: 1999-00 to 2003-04 and 2004-05 to 2008-09

VIC: 2001 to 2005 and 2006 to 2010

QLD: 2001-02 to 2004-05 and 2005-06 to 2009-10

TAS: 2000 to 2003, 2004 to 2007 and 2008 to 2012

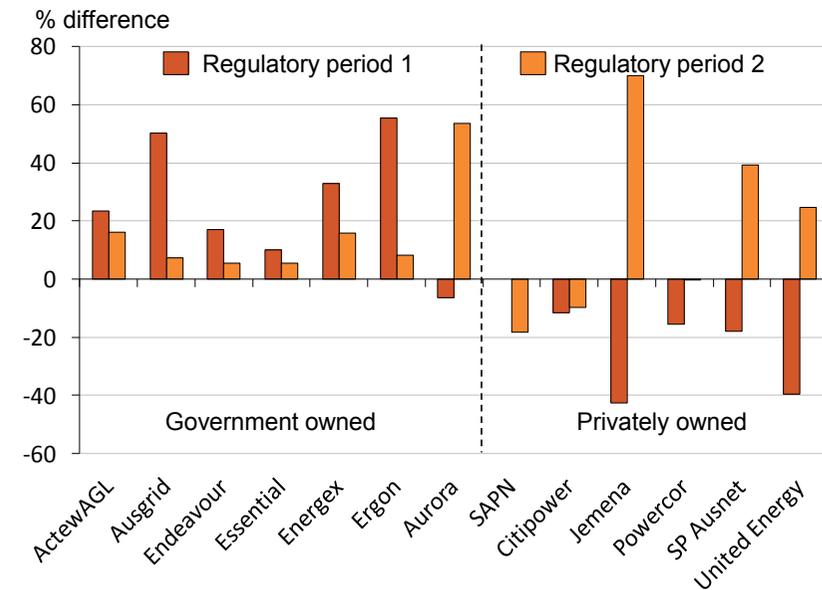
SA: 2000-01 to 2004-05 and 2005-06 to 2009-1

<sup>144</sup> AER cited in Productivity Commission (2012), p 245

Figure 6.1 illustrates the capital expenditure relative to regulated allowances for all of the distribution businesses for the last two regulatory periods. The net capex spent in excess of regulated allowances totalled \$3.6 billion (\$2010). Government companies spent \$3.33 billion in excess and private companies \$300 million (\$2010).

Some reasons for capital expenditure spent in excess of regulatory allowances are within the control of companies.<sup>145</sup> Ausgrid partly attributed its overspending of capex between 2004 and 2009 to a decision to accelerate its replacement of assets, despite insufficient funding being provided for in the regulatory determination.<sup>146</sup>

**Figure 6.1: Percentage difference between forecast and actual capital expenditure by regulatory period**



Sources: Analysis of data obtained from distribution determinations by Australian Energy Regulator (2012a), state-based regulators<sup>147</sup> and regulatory audit reports.<sup>148</sup>

<sup>145</sup> AEMC (2012e), p 122

<sup>146</sup> Productivity Commission (2012) p 245

<sup>147</sup> Queensland Competition Authority (2012c), Independent Pricing and Regulatory Tribunal of New South Wales (2004), Independent Pricing and Regulatory Tribunal of New South Wales (2006), Essential Services Commission of South Australia (2012b), Office of the Tasmanian Economic Regulator (2003) and Office of the Tasmanian Economic Regulator (2007)

<sup>148</sup> Australian Energy Regulator (2012c); Queensland Competition Authority (2012a), Queensland Competition Authority (2012b), Essential Services Commission of South Australia (2012a)

For New South Wales companies Ausgrid, Endeavour and Essential Energy, the over expenditure in the second regulatory period exceeded the additional capex regulators allowed them in order to meet higher reliability standards.

Privately owned companies, by contrast, underspent in regulatory period one. However, several then overspent in the most recently completed regulatory period. It is hard to compare government-owned companies with the privately owned companies in Victoria and South Australia. The latter companies operated under different regulatory incentives to government-owned companies during regulatory period one. These incentives, under an efficiency carryover mechanism, allowed companies to retain a share of capex savings for the subsequent five years.<sup>149</sup> While efficiency gains from 2006-10 were carried over by the AER in the 2011-2015 determination, the scheme itself did not continue.<sup>150</sup>

This analysis suggests that both government-owned and privately-owned companies are likely to overspend when subject to a similar regulatory process. It is not possible to accurately estimate how much of this over-expenditure the companies could have justified. In a proposed rule change, rejected by the AEMC, the AER sought to restrict the amount of over-expenditure the companies could recover by imposing new charges on their customers to 60 per cent of the cost.

Subjecting over-allowance capital expenditure to a prudent investment test could avoid the impact of this element of overspend on consumer prices. Indeed, the very existence of such a test would tend to reduce the likelihood of companies undertaking such expenditure.

### 6.3 The particular problem of demand forecasts

Up to the summer of 2010-11, energy demand in the NEM had been rising steadily for several decades.<sup>151</sup> Forecasts by the industry and regulatory bodies such as AEMO and its predecessor, the National Electricity Market Management Company, suggested this would continue. However, just as steep increases in regulated prices were being passed through to consumers, actual growth in demand for electricity began slowing. More recently, demand has even declined, as shown in Figure 6.2. The causes include a moderation in GDP growth because of the global financial crisis, reduced manufacturing output, penetration of rooftop photovoltaic systems, consumer response to rising electricity prices, and perhaps mild seasonal weather conditions in the last few years. Since there has been no quantitative analysis of these factors, it is difficult to have confidence in the reliability of forecasts of future demand. Therefore, some controls need to be implemented to protect consumers from the adoption of unrealistic demand forecasts.

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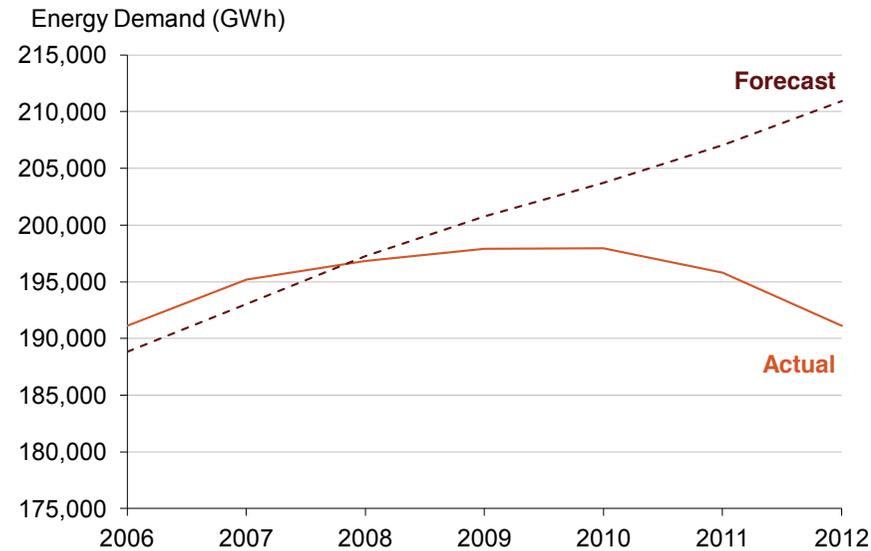
<sup>149</sup> Office of the Regulator-General Victoria (2000), p 84-85. This operates in a similar way to the current Efficiency Benefit Sharing Scheme (EBSS) which applies to operational expenditure

<sup>150</sup> There is no efficiency carry over mechanism relating to capital expenditure in the National Electricity Rules.

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<sup>151</sup> AEMO (2012d), p 3-4

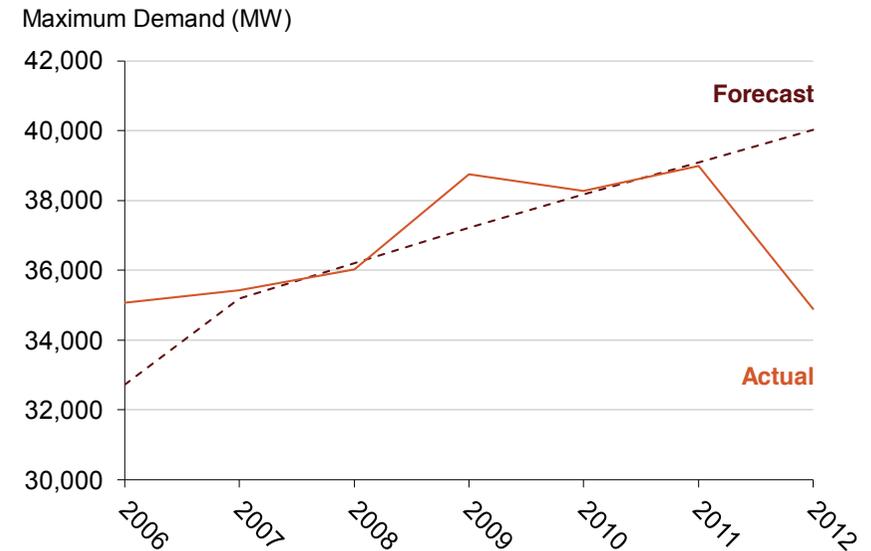
**Figure 6.2: NEM energy demand forecast and actual**



Source: NEMMCO (2006), AEMO (2012d)

Electricity demand is not uniform across a day, week or seasons. Consumer needs vary. Electricity transmission and distribution networks are required to have the capacity to meet maximum levels of energy demand rather than average consumption. As the drivers of energy usage, including greater use of air conditioners and technology in the home, have changed over time, maximum demand had increased beyond growth in average demand. However, as with energy demand, growth in maximum demand flattened – then recently has reduced (see figure 6.3).

**Figure 6.3: NEM maximum demand forecast and actual**



Source: NEMMCO (2006), AEMO (2012d)

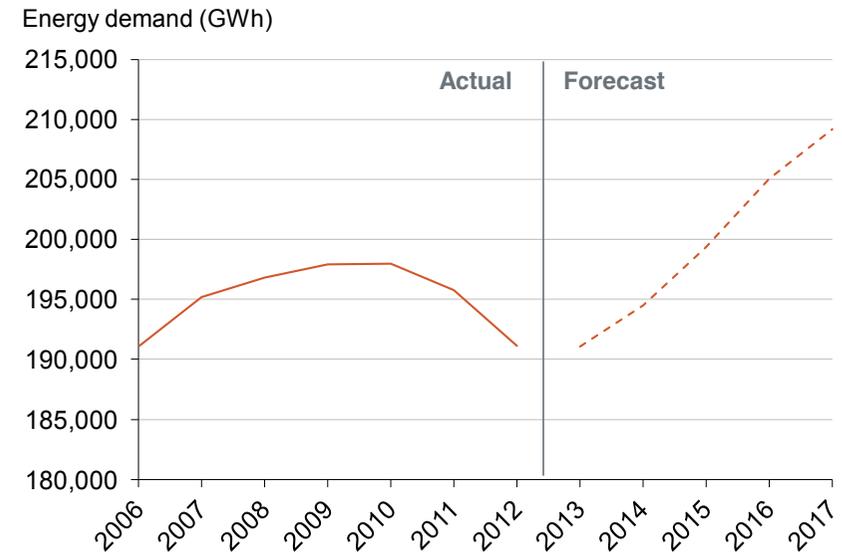
Where investment had been geared to meet these periods of forecast maximum demand growth, that investment is being under-used. The generation sector has already reacted to this development by withdrawing some coal-fired power stations and sending clear signals that major new investment is not required in the near-term.

Regulators approved investments in distribution networks to meet rising demand based on forecasts from only a few years ago and that cost was locked into the prices passed through to consumers.

However, the regulatory process is not flexible enough to respond to recent changes in circumstances. This might have been acceptable when the factors influencing energy demand and supply were evolving more steadily and predictably. That is no longer the case. As Figure 6.4 shows, the latest forecasts by AEMO indicate a return to growth, although from a lower base and at a lower rate than indicated by previous forecasts. Confidence in such forecasts is questionable given the recent history.

AEMO has also published the underlying assumptions on which its projections are based.<sup>152</sup> It is plausible that a return to more extreme seasonal weather, combined with an increase in economic activity with strong energy needs, could reverse this trend. But on the numbers, the forecast for demand looks far too high. It is reasonable for investors in the competitive end of the market – that is, generation and retail – to consider these and their own forecasts when risking shareholder funds, as such investors are continually updating their capital forecasts. It is a different matter when such forecasts lock forward expenditure into the spending plans of regulated businesses.

**Figure 6.4: NEM energy demand actual and forecast**



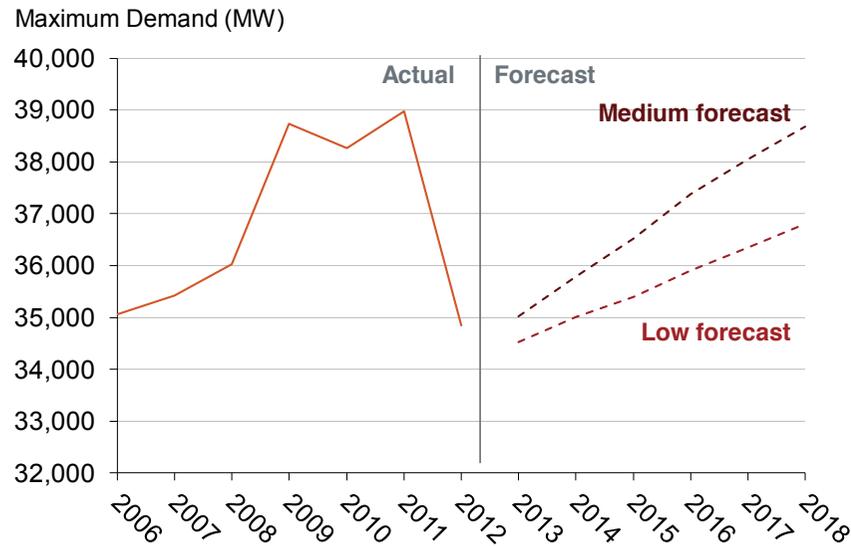
Source: AEMO (2012d)

The current 2012 forecast for maximum demand growth is shown in Figure 6.5 for the middle of the range outcome, together with a lower, but plausible, forecast. If forward capital allowances were to be based on the former, but the actual result came to be the latter, there would be considerable unnecessary capital expenditure.

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<sup>152</sup> Ibid.; AEMO (2012c)

**Figure 6.5: NEM maximum demand actual and forecast (MW)**



Note: Medium and low growth forecasts are based on 90 per cent probability of exceedance (POE).  
Source: AEMO (2012d)

Current capital forecasts over the forward period include \$2.4 billion per year to meet increasing demand.<sup>153</sup> If the lower demand forecast was to unfold and the capital allowances were not changed, the over-expenditure would be of the order of \$5.9 billion over the five-year forecast, on a simple pro-rata basis.

<sup>153</sup> AEMO (2012)

Taking measures to address this problem would therefore deliver annual savings by the fifth year of \$680 million.<sup>154</sup>

To address the problem, this report recommends that regulators continue to use five-year forecasts of capital and operating cost expenditure to form the basis of regulated set revenue for the businesses. However, these forecasts should be revised annually on the basis of forecasts provided each year by AEMO through its National Electricity Forecasting Report. The recently released Energy White Paper cautioned that sustained low demand growth is not a certainty. However, companies being allowed to invest on the basis of a possible rebound will significantly drive up consumer costs.

#### 6.4 Other problems with the process

The Standing Council on Energy and Resources' expert panel has examined flaws in the relationship that the regulatory process causes between the AER and the companies and in the process by which AER determinations can be challenged before the Australian Competition Tribunal.<sup>155</sup> The AEMC,<sup>156</sup> the Productivity Commission,<sup>157</sup> and Mountain and Littlechild<sup>158</sup> have also described such problems. This report does not analyse this work in any detail. However, if these recommendations were adopted, the higher costs that these flaws would cause for consumers would be substantially eliminated.

<sup>154</sup> Based on 9.3 per cent WACC and straight line depreciation over 40 years

<sup>155</sup> Standing Council on Energy and Resources (2012)

<sup>156</sup> AEMC (2012e)

<sup>157</sup> Productivity Commission (2012)

<sup>158</sup> Mountain and Littlechild (2010)

## Appendix One: Sample equity returns

Return on equity (ROE) for distribution businesses, listed equity market and selected companies in comparable industries.

Asset Type	Company / Asset	Mean Annual ROE	Std Dev of ROE
Equity Market	ASX All Ordinaries Accumulation Index	12.4%	20.1%
Risk-Free Asset Proxy	10 Yr Australian Commonwealth Government Securities	5.5%	0.4%
DNSPs (Incl parent/holding companies)	Ausgrid	14.6%	2.9%
	Endeavour Energy	16.1%	2.5%
	Essential Energy	11.3%	3.7%
	Energex	7.0%	1.3%
	Ergon (Adjusted for disposal of retail assets)	7.6%	2.6%
	ETSA	15.3%	6.7%
	Aurora	3.0%	4.2%
	CHEDHA (Incl. Citipower & Powercor)	7.2%	10.2%
	Jemena	10.7%	3.7%
	Powercor (Standalone)	12.2%	7.0%
	SP AusNet	14.4%	14.8%
	United Energy	24.3%	19.5%
Comparables - Electricity (Incl generators/retailers)	Origin Energy (Adjusted for APLNG disposal)	7.9%	4.0%
	TRU Energy	1.5%	29.4%
	AGL	8.5%	3.6%
Comparables - Gas (Infrastructure / utilities, production)	Santos (Adjusted for disposal of non-continuing operations)	13.3%	7.7%
	Woodside	24.8%	8.9%
	Energy Partnership (Gas)	9.5%	6.6%

## Appendix Two: Cost of debt comparisons

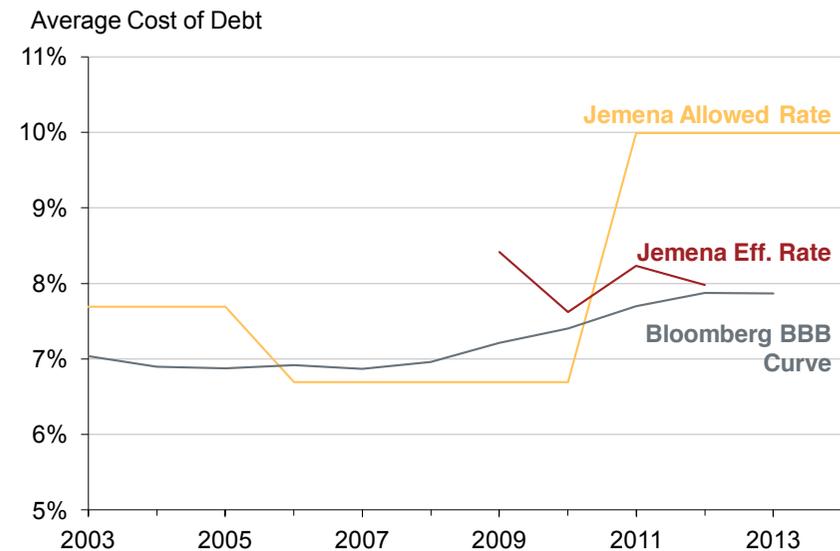
### Detailed cost of debt comparisons for Victorian companies

#### Jemena

Jemena is not financed by any related-party debt, but the company states that its debt is guaranteed by its parent, Singapore Power Ltd (rated AA- by Standard&Poor's<sup>159</sup>), and thus its borrowing costs are lower than they would be on a standalone basis.<sup>160</sup>

The chart shows that Jemena is one of the few examples where the symmetric nature of the risk of difference between determined and actual costs of debt is clear. Windfall gains to customers in the earlier regulatory period are offset by windfall profits to the company in the later period.

Figure A.1 - Jemena's determined and effective costs of debt



Sources: Source: Analysis of data obtained from Bloomberg, company reports, Australian Energy Regulator (2012a) and Essential Services Commission (2006).

<sup>159</sup> Standard & Poor's (2012a)

<sup>160</sup> Company reports: Jemena (2012)

### SP AusNet

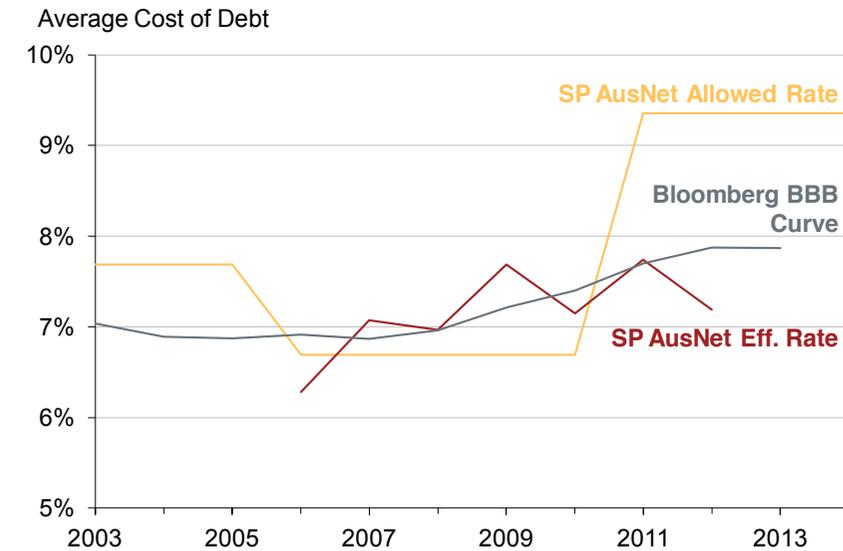
SP AusNet's debt structure does not include any related-party or subordinated debt.<sup>161</sup> However, Standard & Poor's states that:

*Although Singapore Powers does not – and is not expected to – guarantee SP AusNet-related debt, its ownership and market reputation assist SP AusNet's access to capital markets.<sup>162</sup>*

Standard & Poor's consider that SP AusNet would hold a credit rating of BBB+ on a standalone basis.<sup>163</sup>

As with Jemena, there is some symmetry to the risk of difference between the determined and actual costs of debt. However the considerable windfall gains for SP AusNet in the later period more than outweigh the earlier losses.

Figure A.2 - SP AusNet's determined and effective costs of debt



Sources: Source: Analysis of data obtained from Bloomberg, company reports, Australian Energy Regulator (2012a) and Essential Services Commission (2006)

<sup>161</sup> SP AusNet (2012)

<sup>162</sup> Standard & Poor's (2012b), p 2

<sup>163</sup> Ibid., p 2

### United Energy

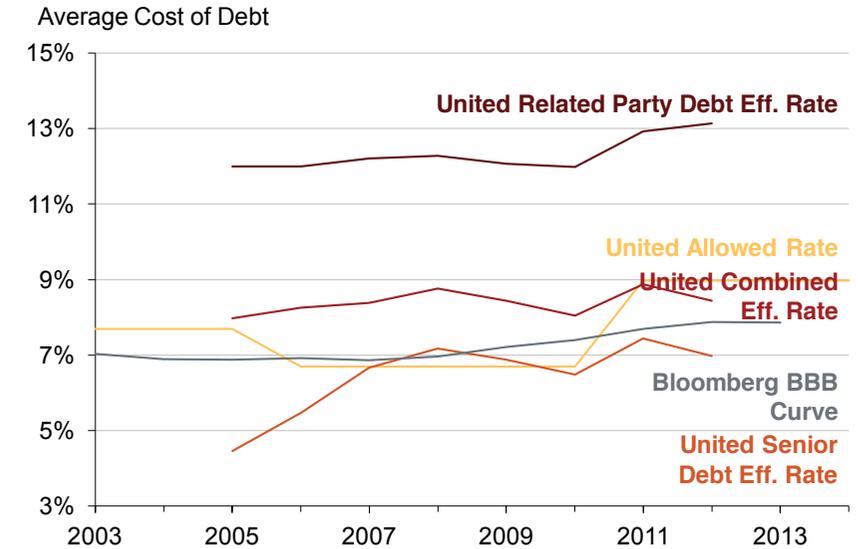
United Energy's debt structure includes senior debt sourced from banks and bondholders, as well as related-party debt sourced from its parents. This debt takes the form of preference shares (stapled to ordinary equity and held by its parents) and Secondary On-Lending Arrangement ('SOLA') subordinated debt from its parent DUET (which was repaid in 2011).<sup>164</sup>

The related party debt acts like equity – it absorbs losses before the debt of the banks and bondholders, and earns a higher rate of return to compensate for this risk. However, its link to United's owners implies that the financial support it provides may be in place regardless of its classification as debt or equity. This suggests that there would be no need for an additional margin on the cost of senior debt were it to be considered equity, as the senior lenders would still face similar levels of risk.

The equity-like subordinated debt earned rates of return between approximately 9 and 13 per cent. The preference shares earned a rate in excess of the determined rate of return for equity of approximately 10.3 per cent, despite occupying a higher (less risky) position in United's capital structure.<sup>165</sup>

Figure shows estimates of an overall effective cost of debt, as well as the effective costs of related party and non-related party debt.

Figure A.3 - United Energy's determined and effective costs of debt



Sources: Source: Analysis of data obtained from Bloomberg, company reports, Australian Energy Regulator (2012a) and Essential Services Commission (2006);

<sup>164</sup> DUET Group (2012)

<sup>165</sup> Analysis of data obtained from Bloomberg, company reports, Australian Energy Regulator (2012a) and Essential Services Commission (2006);

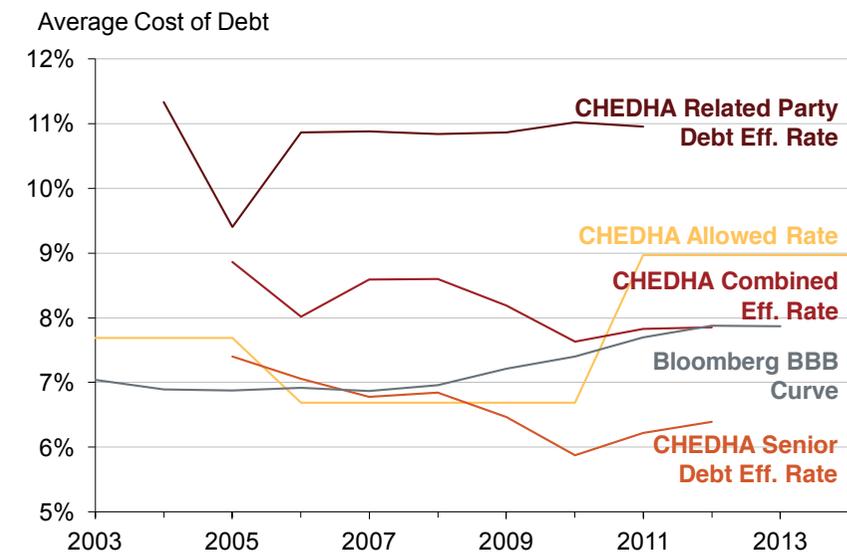
### Citipower / Powercor (CHEDHA)

The parent company CHEDHA's debt structure includes subordinated related party loans from its owners, Cheung Kong Infrastructure Ltd (51 per cent) and Spark Infrastructure (49 per cent), that earn approximately 400-500 basis points above the cost of senior debt.<sup>166</sup>

As in the United Energy case, the related party debt acts like equity – it absorbs losses before the debt of the banks and bondholders, and earns a higher rate of return to compensate for this risk. However, its link to the CHEDHA companies' owners implies that the financial support it provides may be in place regardless of its classification as debt or equity. This suggests that there would be no need for an additional margin on the cost of senior debt were it to be considered equity, as the senior lenders would still face similar levels of risk.

Figure shows estimates of an overall effective cost of debt as well as the effective costs of related party and non-related party debt.

Figure A.4 - Citipower and Powercor's determined and effective costs of debt



Sources: Source: Analysis of data obtained from Bloomberg, company reports, Australian Energy Regulator (2012a) and Essential Services Commission (2006);

<sup>166</sup> Citipower (2012), Powercor (2012)

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