UNITED ENERGY
Distribution

Revised Regulatory Proposal for Distribution Prices and Services

January 2011 – December 2015

United Energy Distribution
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Introduction

In accordance with the National Electricity Rules (the Rules), this submission is the Revised Regulatory Proposal of United Energy Distribution Pty Ltd (UED) for the regulatory period commencing 1 January 2011. It responds to the issues raised by the AER in its Draft Decision, which was published on 31 May 2010.

UED is one of five electricity distribution businesses in Victoria. UED manages network assets with a replacement value of almost $3.7 billion, and provides network services to almost 630,000 customers in south-east Melbourne and the Mornington Peninsula. UED is regulated by the Australian Energy Regulator (the AER) in accordance with the National Electricity Law and the Rules.

In accordance with the Rules, UED submitted its original Regulatory Proposal to the AER on 30 November 2009. The original Regulatory Proposal described UED's expenditure plans and revenue requirements for the period from 1 January 2011 to 31 December 2015. UED highlighted the challenges in the forthcoming regulatory period and the revenue it requires in order to deliver reliable network services in accordance with the Rules.

In its original Regulatory Proposal, UED provided detailed substantiation of its view that average prices would need to increase by approximately 16 percent in 2011 in real terms and by 4 percent per annum thereafter. The composition of UED's building block revenue requirement is provided in the table below.

Table E1 Proposed total revenue requirements

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Return on Capital	115.7	124.1	131.1	137.2	141.6
Depreciation	84.0	89.7	96.6	100.7	105.2
Non-capital costs	123.8	120.2	119.7	119.2	118.9
Efficiency carry-over	9.2	6.0	-1.6	-1.4	0.0
Estimated cost of corporate income tax	6.2	7.3	8.6	11.0	12.4
Total Revenue	**339.0**	**347.4**	**354.4**	**366.6**	**378.0**

Amounts shown in real 2010 terms.

The AER's Draft Decision did not accept UED's original Regulatory Proposal. The AER has instead imposed significant reductions in UED's proposed expenditure and revenue requirements. These reductions include a 23 per cent cut in UED's forecast operating expenditure and a 33 per cent reduction capital expenditure forecasts for the forthcoming regulatory period. UED is concerned that the Draft Decision provides expenditure allowances that are unsustainably low, inconsistent with maintaining network reliability, and contrary to the interests and expectations of customers, shareholders and the wider community.

It is important to recognise that UED will manage its capital expenditure within the allowance provided by the AER. Unlike Government owned networks, UED cannot avoid the commercial and financial constraints that result from regulatory determinations. The AER must accept that imposing reductions on UED's proposed capital expenditure will directly affect network reliability. UED believes that the Draft Decision will deliver outcomes that are contrary to the interests of customers, and contrary to the National Electricity Objective.

In terms of financing costs, the AER also rejected UED's view that the global financial crisis has led to a significant increase in the cost of capital. In addition, the AER's approach to closing out the ESCV's service incentive (S-factor) scheme has incorrectly imposed substantial penalties on UED. UED contends that these outcomes are also inconsistent with the requirements of the Rules and the National Electricity Law.

We see it as essential that the AER reconsiders its conclusions and delivers a workable outcome for UED and its customers and shareholders, which properly accords with the requirements of the National Electricity Law and the Rules.

No Basis to conclude UED's forecasts are inefficient

The Rules require the AER to assess whether UED's operating expenditure and capital expenditure forecasts reasonably reflect efficient and prudent costs. The Rules state that the AER must accept UED's forecast expenditure if it satisfied that those forecasts meet the requirements of the Rules. It is not open to the AER to simply replace UED's forecasts with its own projections.

By rejecting UED's forecasts, the AER has concluded that UED's forecasts are inefficient or imprudent. However, UED does not consider that the AER has any valid basis to reach this conclusion. The sections below (in particular Figures E1 to E4) highlight that the AER has previously deemed far higher expenditure levels as efficient – particularly in its recent NSW and Queensland decisions.

UED considers that the AER has established clear precedents by adopting the expenditure forecasts that it has in NSW and Queensland. The AER must consider the precedent that it has set in other jurisdictions when it examines the efficiency and prudency of UED's expenditure forecasts. The AER's conclusion that UED's expenditures are inefficient is inconsistent with the AER's approval of expenditures in other jurisdictions that are up to 4 times greater on a per customer basis than UED's.

Two important consequences flow from the AER's Draft Decision.

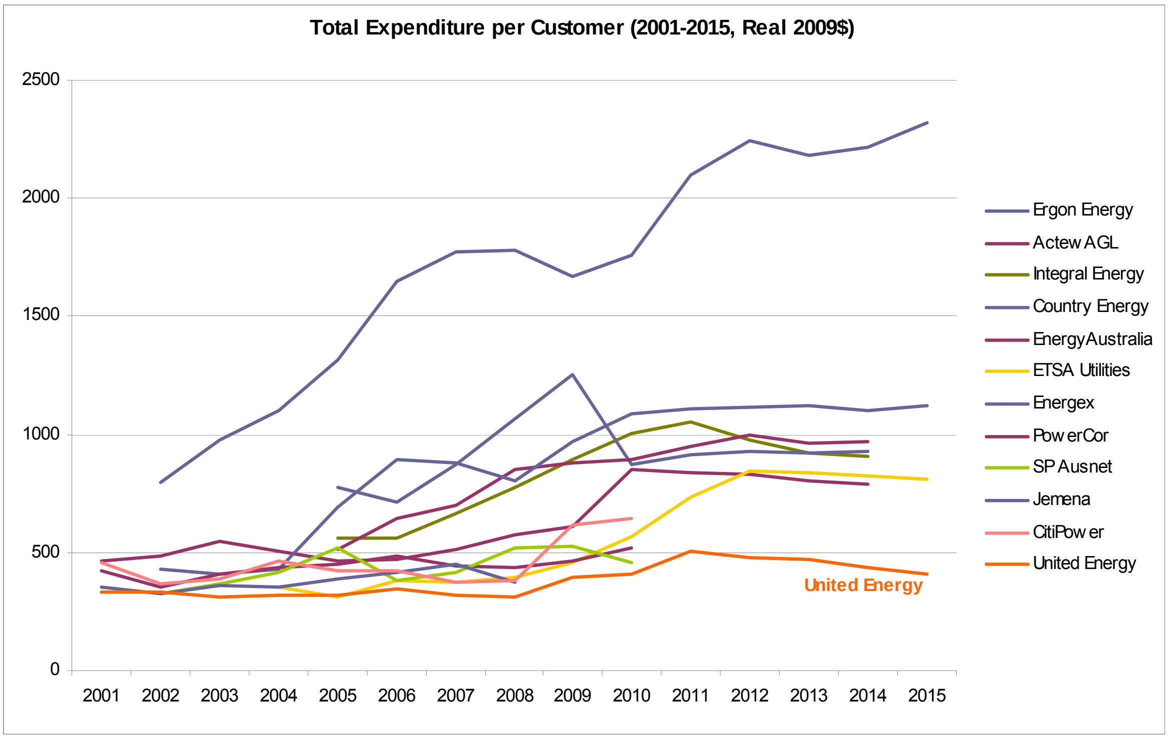
Firstly, the Draft Decision would have serious financial implications for UED. This financial impact will ultimately affect our customers because expenditure will be constrained to the levels set by the AER. In medium term, the AER is embarking on a course of action that will deliver better electricity infrastructure to the NSW consumer compared to Victorian consumers. Such an outcome sits uncomfortably with the new national energy framework that has been developed in recent years.

Secondly, the AER's regulatory approach will have a chilling effect on future incentives and the drive for efficiency. The AER's approach to UED's operating expenditure forecasts shows that the AER is reluctant to recognise the commercial reality that the pursuit of efficiency gains may require the adoption of new business structures. The AER, however, is apparently unwilling to assess UED's forecast operating expenditure and the judgments that UED has made. Instead, the AER's Draft Decision makes projections – not forecasts or estimates of UED's operating expenditure – based on a false premise that the status quo will continue. The AER's approach sends a very strong message that businesses should never take risks and never seek to move from the status quo, and that continuing along in a no-change world is the best approach in terms of managing regulatory risk. UED considers this outcome to be contrary to the National Electricity Objective and therefore counter to the AER's obligations under the National Electricity Law.

UED is an efficient cost performer

UED's original Regulatory Proposal explained that UED has delivered lower prices and better reliability to customers over the course of the current and previous regulatory periods. Figure E1 below shows that whilst costs have drifted upwards for a number of distributors, UED has maintained its position as a low cost performer. UED's original Regulatory Proposal included Figure E1 below, which shows UED to be the lowest cost performer across the 12 distribution businesses in the mainland National Electricity Market. A proper application of the National Electricity Law and Rules would reward low cost performers such as UED, rather than impose yet further price reductions.

Figure E1: Comparison of total expenditure per customer for distribution companies



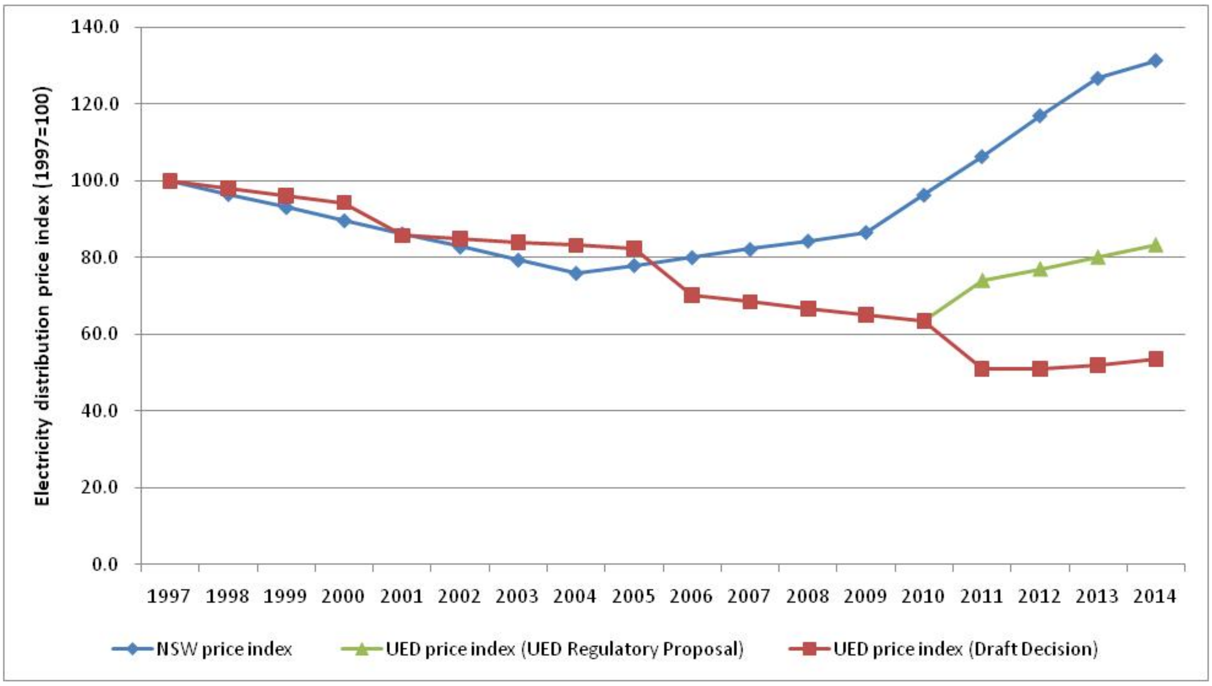
In this Revised Regulatory Proposal, UED has provided further evidence to demonstrate that UED is an efficient cost performer and that UED's original Regulatory Proposal compares well with its peers. UED draws the AER's attention to a paper by Bruce Mountain and Professor Stephen Littlechild, which was published in December 2009 by the Electricity

Policy Research Group of the University of Cambridge[1]. UED notes that this paper has been strongly supported by the EUAA, a body that represents UED's customers. Pages 19 to 23 of the Mountain and Littlechild paper stated:

> "Peak demand in the Victorian power system has grown at a compound annual rate of 4.5% between 2002 and 2008 compared to 3.0% growth in NSW. Distributor customer numbers in Victoria have been growing at an annual average rate of 1.9%, roughly twice the rate in NSW. Quality of supply as measured by the frequency and duration of outages has consistently been better in Victoria than in NSW.
>
> These data suggest that, in terms of customer density, size of company and growth in demand, Victoria is faced with more demanding conditions as NSW, and has delivered better quality of service. If these factors are significant, this should lead to higher previous and projected costs and revenues in Victoria than in GB and also higher than in NSW.
>
> The evidence suggests that the first proposition is true but the second is not."

The Mountain and Littlechild paper provides numerous benchmarking measures which indicate that the Victorian distributors are superior cost performers compared to NSW. The Mountain and Littlechild analysis indicates that the gap between the high prices in NSW and the low prices in Victoria should narrow. On the contrary, however, a comparison (shown in Figure E2 below) between UED's price path under the AER's Draft Decision and the AER's April 2009 Final Decision for the NSW businesses illustrates that the AER is seeking to further widen the existing gap. The Figure also shows UED's proposed price path, which increases at a slower pace than the AER's approved prices in NSW.

Figure E2 Comparison of CPI-X price paths: UED and New South Wales distributors



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[1] Bruce Mountain and Stephen Littlechild, Comparing electricity distribution network costs and revenues in New South Wales and Great Britain, EPRG Working Paper 0930, December 2009.

The price comparison presented above illustrates that:

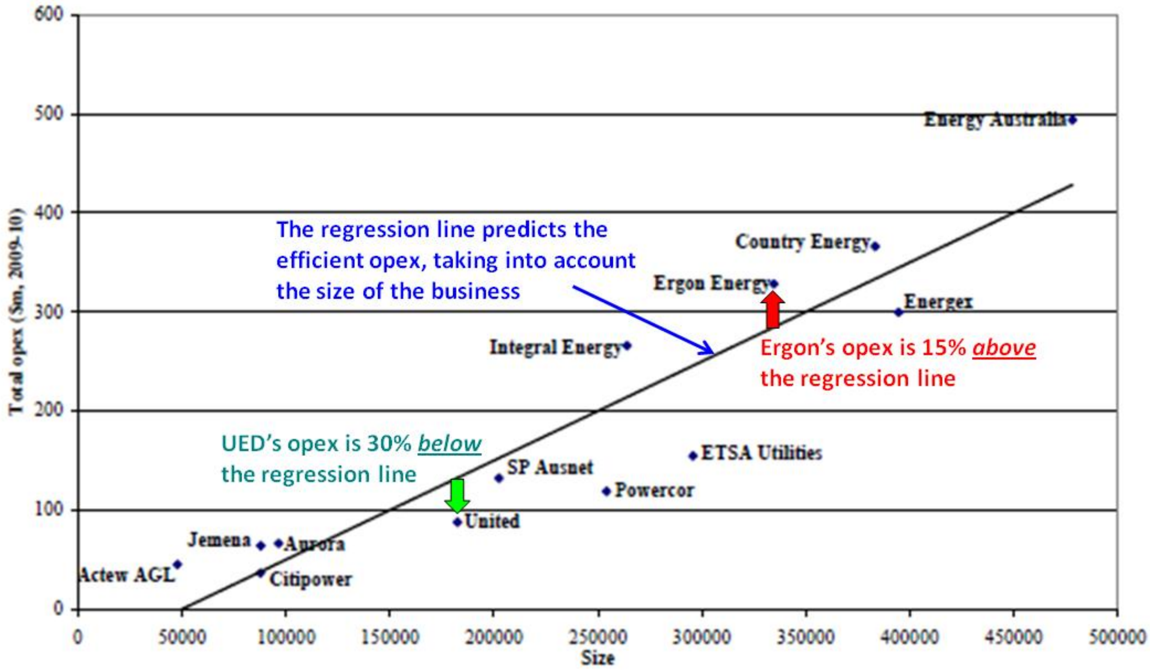
- The price increases originally proposed by UED for the forthcoming regulatory period are modest compared to those approved by the AER in its April 2009 determination for NSW distributors;

- If UED's original proposal were to be accepted, UED's distribution prices in 2014 would be 37 per cent lower than those already approved by the AER for New South Wales; and

- If the price controls in the Draft Decision were to be implemented, UED's distribution prices in 2014 would be 60% lower than those approved by the AER in NSW. Under this scenario, distribution prices in NSW would be more than double those of UED by 2014.

Similar conclusions can also be drawn in relation to the Queensland distributors. The following regression analysis, which we have annotated, appears as Figure I.3 in Appendix I of the AER's Draft Decision of 25 November 2009 on Queensland DNSPs.

Figure E3 Annotated reproduction of Figure I.3 from AER's Draft Decision for Queensland



The AER's regression analysis essentially benchmarks the Australian DNSPs by comparing each DNSP's actual costs with its predicted cost (indicated by the straight line) based on its size. The analysis shows that UED's operating expenditure is approximately 30% lower than the efficient expenditure predicted by the AER's analysis.

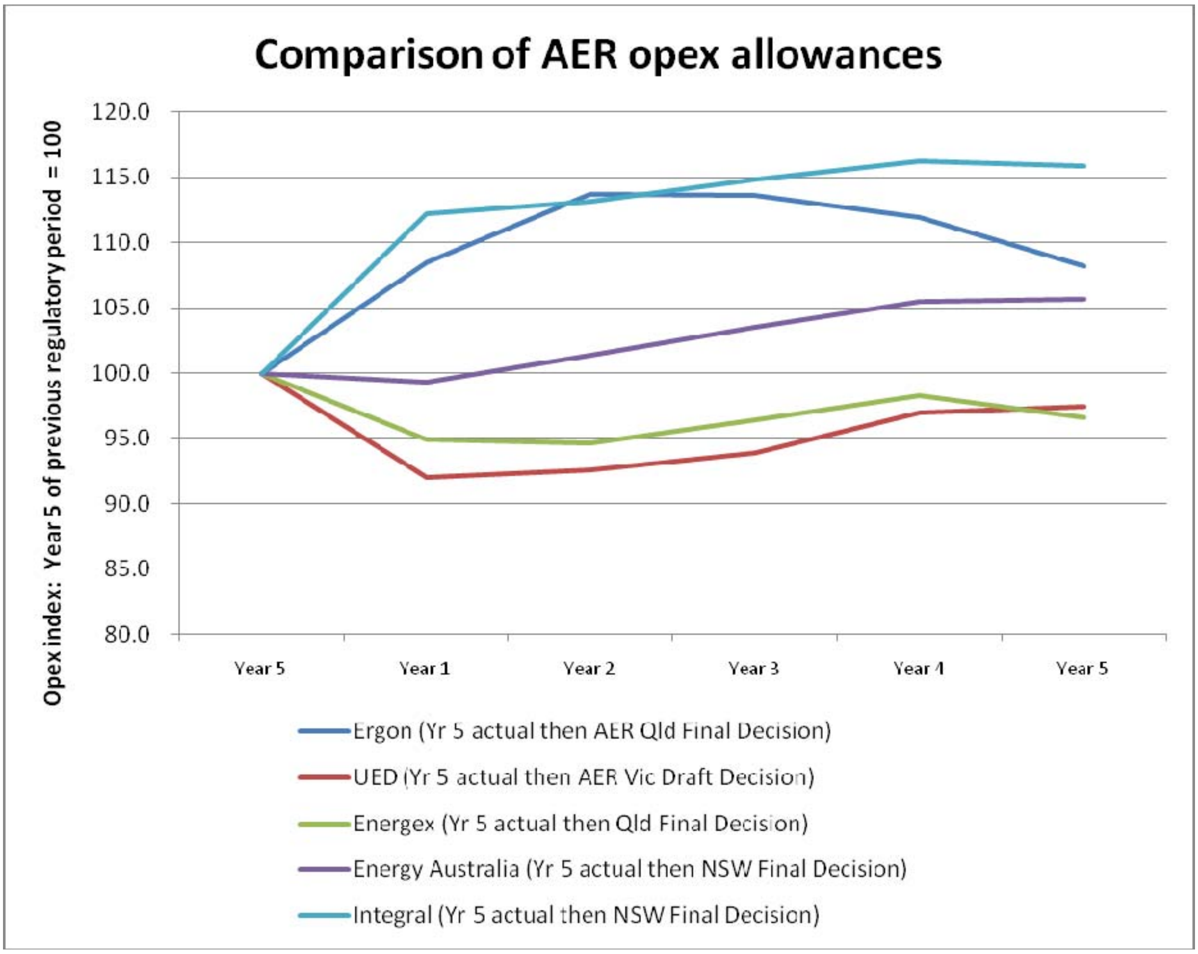
UED has obtained an independent expert opinion from Philip Williams of Frontier Economics, which includes a consideration of the AER's benchmarking analysis. In this independent expert report, Philip Williams comments on the AER's benchmarking analysis in the following terms[2]:

> "In my view, the AER's benchmarking analysis in Appendix I of its Draft Decision and noted above does not go far enough to allow the AER to properly assess whether UED's forecast operating expenditure is efficient. The AER itself concedes that the data used in its analysis have not been corrected for differences in regulatory environment, asset classifications, network maturity and geographical factors. In addition, the AER's findings in its draft decision on the Queensland DNSPs also appear too limited to come to firm conclusions, although they do show UED to be significantly more efficient than most DNSPs in the NEM.
>
> Keeping these caveats in mind, I note that on their face, per customer revenues of DNSPs in Victoria appear to be significantly lower than per customer revenues for DNSPs in New South Wales and this seems to be in part the result of lower operating expenditure per customer by Victorian DNSPs. This difference in expenditures may be due to non-efficiency reasons, but the AER's analysis does not show this to be the case. In this context, I find it odd that the AER has rejected UED's operating expenditure forecast as not reflecting efficient and prudent costs."

A comparison (shown in Figure E4 below) of the AER's Draft Decision for UED with recent Final Decisions for a selection of four Queensland and NSW DNSPs provides further evidence that supports Philip Williams' observation that the AER's rejection of UED's expenditure forecasts is odd.

[2] Philip Williams, Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery, July 2010, paragraphs 70 and 71.

Figure E4 **Comparison of AER opex allowances for UED in the June 2010 Victorian Draft Decision and a sample DNSPs from the April 2009 NSW Final Decision and the Queensland May 2010 Final Decision**



The analysis indicates that the AER's Draft Decision for UED is inconsistent with the outcomes of the AER's determinations in other jurisdictions. This is particularly concerning given the similarities in the broad circumstances of all Australian DNSPs, in terms of:

- sustained upward pressures on labour and contracts costs in the context of an on-going resources boom and national markets for labour and materials;
- the need to increase investment and maintenance as the electricity distribution infrastructure installed across Australia in the post-war era ages and approaches the end of its serviceable life;
- the need to meet increasing peak demand and to connect new customers in a national economy that has exhibited sustained strong growth over the past decade;
- the need to comply with common health, safety, environmental and technical regulatory obligations; and
- the additional investment and operating expenditure required to address issues relating to climate change.

Consistent regulatory decision-making through time is essential to ensure the ongoing integrity of the regulatory framework. The analysis set out above demonstrates that the AER has adopted an inconsistent approach in its application of the Rules in the Victorian

Draft Decision, compared to the approach it adopted in its recent Queensland and NSW determinations. UED contends that this type of inconsistency does not promote effective incentives or economic efficiency, as required by the Revenue and Pricing Principles in the National Electricity Law. Furthermore, UED considers that the AER's imposition of very significant reductions in UED's operating expenditure forecasts is unjustified and unreasonable in light of:

- the results of the AER's own benchmarking analysis, which shows UED to be a superior performer compared to the NSW and Queensland DNSPs; and

- the comparatively high expenditure forecasts accepted by the AER as being efficient in the NSW and Queensland Final Decisions.

In short, there is no reasonable basis for the AER to deem UED's expenditure forecasts inefficient, in light of the expenditure forecasts that the AER has accepted in its NSW and Queensland determinations.

UED's new business model and operating expenditure forecasts

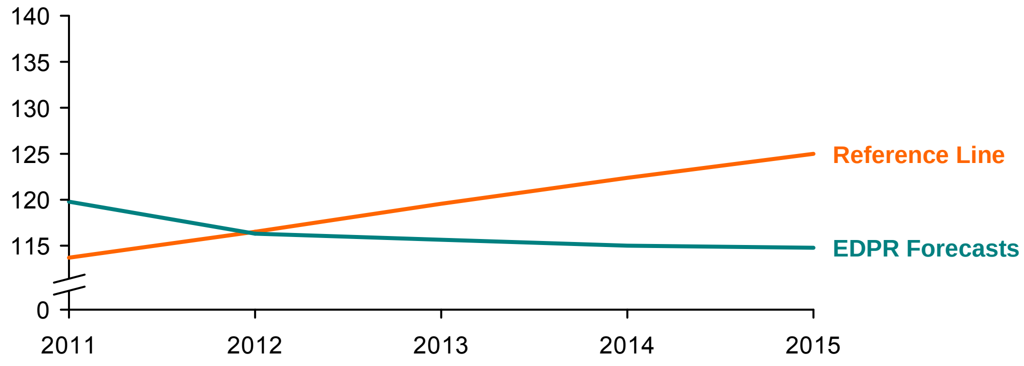
Despite the significant benefits delivered to date, UED's original Regulatory Proposal explained that UED intended to transform its current business model. UED's existing Operating Services Agreement (OSA) with Jemena Asset Management (JAM) expires on 30 June 2011. UED's new business model provides an opportunity to consolidate and build on the efficiency and service improvements that have been achieved to date, whilst also addressing the OSA's operational and regulatory difficulties that have become increasingly apparent in recent times.

UED explained that the OSA services have been subject to an open and highly competitive retendering and recontracting exercise. UED's new business model adopts a 'best of breed' contractor model, in which UED and its customers obtain the cost and service benefits from consortia that combine the best performers for each service area.

The resulting business model, which sees UED bringing more services in-house, has been accepted by the UED Board as prudent and efficient. The Board's resolution on this issue was supported by international experience and independent advice from outsourcing experts, AT Kearney. The Board's decision to conduct the retendering exercise and implement the new business model was vindicated by the tender results.

UED's original Regulatory Proposal provided a comparison of two operating expenditure scenarios: a "reference line" (which is a projection of operating costs under the existing business model), and the operating expenditure forecasts for UED's proposed new business model (denoted "EDPR forecast"), based on the bid provided by the lowest cost consortium in the recent tender process, as shown in Figure E5 below.

Figure E5: UED's five year comparisons (OPEX) – DUOS opex only



Note: The reference line in figure E5 is calculated based on the actual cost of services in the 2008 and 2009 years projected forward in the light specific known cost changes and externally developed general cost escalators.

UED explained that the new business model is expected to deliver much improved outcomes over a five year period, demonstrating the benefits of the proposed restructuring, and the best of breed contractor model adopted by UED. The original Regulatory Proposal also explained that extending the analysis beyond the five year period provided compelling support for the new business model, and justified the upfront investments needed to deliver the new business model.

UED's original Regulatory Proposal highlighted that the Rules require UED to submit forecasts of annual operating expenditure for the forthcoming regulatory period, and that these forecasts are certified by UED's Directors. Consequently, UED could not employ a 'year 4' roll forward method to forecast operating expenditure as this method inappropriately assumes 'business-as-usual' operating conditions.

UED's original Regulatory Proposal provided a number of expert reports and independent evidence to support its operating expenditure forecasts, as noted in the table below.

Table E3 Expert reports and independent evidence to substantiate UED's original Regulatory Proposal

Matter addressed	Expert/Evidence	Reference
1. Advice on the optimal design of UED's business model	AT Kearney	Regulatory Proposal, Appendix F4
2. Probity plan for the competitive tender process for outsourced services, and subsequent audit	Dench McClean Carlson	Regulatory Proposal, Appendix F6
3. Opinion that UED's expenditure forecasting methodology has been designed and implemented to provide forecasts that comply with the Rules	KPMG	Regulatory Proposal, Appendix C1
4. Opinion that UED's asset management plan adopts work volumes that are consistent with 2009 volumes	AECOM	Regulatory Proposal, Appendix D5
5. Information to demonstrate that salary benchmarks for internal labour are reasonable	Hays 2009 Salary Guide; Hudson 2009 Salary Guide; Michael Page 2009 Salary Guide; and Geoffrey Nunn & Associates Labour Cost Benchmarks.	Provided to AER on confidential basis, 9 March 2010
6. Escalators for internal labour costs based on forecast wages for Victorian distribution businesses	BIS Shrapnel	Regulatory Proposal, Appendix D1
7. Information to demonstrate that internal labour is consistent with European utility benchmarks	AT Kearney	Provided to AER on confidential basis, 9 March 2010
8. Opinion that UED's corporate costs for the new business model are efficient when compared against industry benchmarks	KPMG	Regulatory Proposal, Appendix C1, appendices K and L

The AER's Draft Decision did not accept UED's operating expenditure forecasting methodology or the resulting forecasts. The AER concluded its assessment of UED's operating expenditure forecast in the following terms[3]:

> "The AER considers that United Energy conducted a reasonably competitive tender process and so the unit costs for outsourced services arising from this tender reasonably reflect efficient costs. However, these unit costs are only one of four components of United

[3] AER, Draft Decision, page 235.

> Energy's opex forecast. The AER considers that the reasonableness of the other three components (in-house unit costs, in-house unit volumes, out-sourced unit volumes) has not been substantiated in United Energy's proposal or in the additional information provided by United Energy in response to the AER's information requests."

The AER relied on the 'revealed cost' or 'year 4' approach to develop an alternative assessment of UED's operating expenditure for the forthcoming regulatory period. In its assessment, the AER made a number of adjustments to UED's base year costs. As a result, the AER's revised operating expenditure forecast for UED imposes a 23 per cent reduction compared to UED's forecasts.

In this Revised Regulatory Proposal, UED reiterates that the new business model necessitates a 'bottom up' forecasting approach, rather than a 'year 4' approach as adopted by the AER's Draft Decision. UED's operating expenditure forecasts for the forthcoming regulatory period must ensure that UED has a reasonable opportunity to recover at least the efficient costs incurred in providing services, as required by the revenue and pricing principles set out in the National Electricity Law. It is not appropriate for the AER to impose an operating expenditure allowance on UED based on the false assumptions that UED's assets are not aging, that upward cost pressures are reducing, or that UED can or should avoid the costs associated with implementing a more effective business model that will deliver long term benefits to consumers by ensuring costs remain efficient and service standards are maintained.

In this Revised Regulatory Proposal UED has provided further substantiation of its original operating expenditure forecasts. In particular, UED has explained that:

- The forecast volume of work for outsourced services is consistent with 2009 actual data.

- The competitive tender exercise required bidders to submit budget forecasts, which comprise price and volume. Therefore, the AER is incorrect to conclude that the competitive tender process can be relied upon to set the unit costs, but not work volumes.

- In-house costs are substantially "non-labour" rather than labour. Non-labour costs cannot be considered in "unit cost" and "work volume" terms as these costs include items such as travel and accommodation, rent and rates.

- In-house labour costs have been developed through a comprehensive benchmarking exercise in terms of staff numbers and wage rates.

UED has also obtained a further independent opinion from KPMG which confirms that:

- UED has provided information that supports its expenditure forecasts;

- the links between the supporting source material and the forecast expenditure components are clearly established;

- UED designed and applied a highly transparent and structured approach to developing its expenditure forecasts in accordance with the relevant requirements of the National Electricity Rules and good forecasting practice; and

- In reaching its Draft Decision the AER has neither explained the substantiation for future events that it reasonably expects of UED, nor why it believes that the assumptions that underpin UED's operating expenditure forecast are unreasonable.

The AER has applied its preferred 'year 4' method to estimate UED's operating expenditure forecasts. UED considers the AER's approach to be inconsistent with the Rules requirements. In addition, the AER has applied a number of inappropriate adjustments and scaling factors in its 'year 4' method. For example:

- the AER has removed the costs of services provided by DUET and AMPCI, even though these services have been provided to UED for 7 years and have contributed to UED's efficient performance; and

- the AER has adopted the ESCV's assumption made in October 2005 regarding the change in UED's operating expenditure between 2009 and 2010. UED considers it inappropriate for the AER to adopt an assumption that was made in October 2005, without any verification or analysis to show that the assumption is valid. This Revised Regulatory Proposal shows that the ESCV's assumption is not valid. In any event, the AER should have adopted its own estimate, rather than rely on a forecast that is almost 5 years old.

Further modifications to the AER's roll forward model are required in order to provide a like-for-like comparison with UED's new business model. In particular, UED's new business model provides superior outcomes in terms of risk management; service performance and governance. Similarly, it is important to recognise that the AER is using JAM's 2009 costs as a basis for forecasting UED's operating expenditure. As noted in an independent expert report prepared by Philip Williams of Frontier Economics, it is not reasonable to assume that JAM will continue to provide these services at zero profit margin. To provide a realistic assessment of UED's future operating expenditure an allowance for a profit margin consistent with that applied by the AER in the NSW electricity distribution review should be included.

The AER's 'year 4' method modified to reflect UED's adjustments and corrections demonstrates that UED's operating expenditure forecast for its new business model is prudent and efficient and complies with the Rules. Specifically:

- UED's total operating expenditure forecast for the next regulatory period is $637.5 million, as shown in the table below.

- The correct application of the AER's year 4 roll-forward model indicates a total estimated operating expenditure for the same 5 year period of $668.7 million before any allowance is made for the additional outputs to be delivered by the new business model.

Clause 6.5.6(c) of the Rules requires the AER to accept UED's operating expenditure forecast if the AER is satisfied that the total of the forecast operating expenditure reasonably reflects the criteria set out in that clause. UED considers that the Draft Decision fails to demonstrate that UED's operating expenditure forecast does not meet the operating expenditure criteria. Moreover, UED has provided extensive and detailed information, including numerous independent expert opinions which demonstrate that the company's expenditure forecasts reasonably reflect the efficient and prudent costs of meeting the operating expenditure objectives. In accordance with the requirements set out in clause 6.5.6(c) of the Rules, the AER must accept UED's operating expenditure forecasts.

The table below provides a summary of UED's operating expenditure forecasts for the purpose of this Revised Regulatory Proposal.

Table E4: UED's revised forecast operating expenditure ($M in 2010 dollars)

	YEAR ENDING 31 DECEMBER					Total $M
	2011	2012	2013	2014	2015	
MAINTENANCE						
Routine	12.2	12.0	10.6	10.6	10.6	55.9
Condition based	12.6	10.5	10.5	10.5	10.5	54.6
Emergency based	6.7	5.8	5.8	5.8	5.8	30.0
Other maintenance	4.4	4.8	4.8	4.8	4.8	23.5
Sub-total maintenance	**35.9**	**33.1**	**31.7**	**31.7**	**31.7**	**164.0**
OTHER FUNCTIONS						
Network operating	31.3	31.6	32.1	32.0	32.1	159.1
SCADA/Network control	5.5	5.9	5.9	5.9	5.9	28.9
Billing & revenue	2.5	1.8	1.8	1.8	1.9	9.8
Customer service	7.8	8.2	8.2	8.1	8.2	40.4
Advertising	1.8	0.6	0.6	0.6	0.6	4.3
Regulatory	3.3	2.3	2.3	2.5	2.8	13.2
Self insurance	3.5	3.5	3.5	3.5	3.5	17.7
Debt raising	0.8	0.8	0.9	0.9	1.0	4.3
Other	39.5	40.5	39.3	38.7	37.6	195.8
Sub-total other functions	**96.0**	**95.2**	**94.6**	**94.0**	**93.6**	**473.5**
Total operating expenditure	**131.9**	**128.3**	**126.3**	**125.7**	**125.3**	**637.5**

Amounts shown in real 2010 terms.

UED's capital expenditure forecasts

UED's original Regulatory Proposal explained that capital expenditure would need to increase significantly in the forthcoming regulatory period. The projected increase in capital expenditure is required to address emerging network issues and to enable UED to continue to deliver reliable services to our customers. The key factors driving the required increase in capital expenditure requirements are as follows:

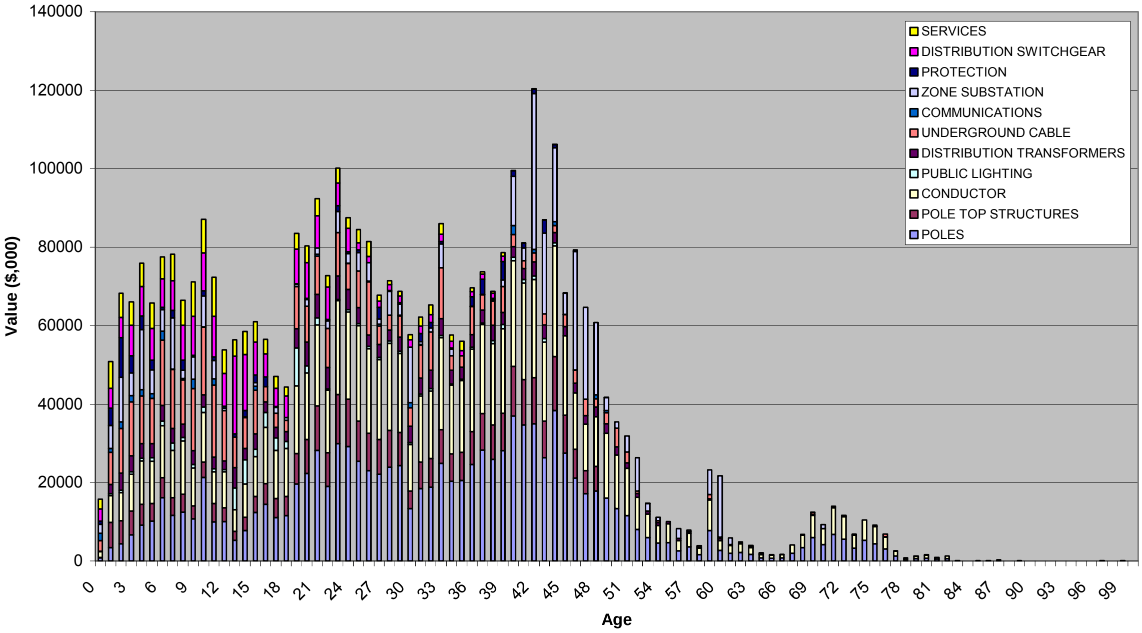
- Increasing penetration of domestic air conditioning is driving growth in summer maximum demand at a rate more than double the growth in energy consumption on average.

- Climate change has emerged as an immediate issue for the Australian power distribution sector and UED. It is no longer prudent for UED to manage future network performance on the basis of an assumption that past climatic conditions will continue. It is vital that UED's network is made more resilient to the effects of bushfire and more critically, reduce the risk of fire start due to network asset operation or failure.

- Changes in safety legislation present a major shift away from previous arrangements, and have also prompted UED to accelerate the replacement of aged assets which have a direct potential impact on public safety.

- The age profile of UED's distribution network reflects the large historical investment that took place in the electricity networks in Victoria to accommodate the arrival of the "baby boomers". The graph of network age profile shown in Figure E6 below indicates the extent of this investment.

Figure E6: UED asset age profile by replacement value



Following its review of UED's capital expenditure proposal, the AER did not accept UED's capital expenditure forecasts, and instead developed its own estimates of UED's capital expenditure requirements. The AER relied heavily on advice from Nuttall Consulting, and an analysis of UED's historic capital expenditure. In a number of respects Nuttall Consulting adopts an unorthodox approach to assessing UED's capital expenditure forecasts. For example, contrary to the evidence presented in the above figure, Nuttall Consulting's approach to replacement capital expenditure assumes that there will be no bow wave in asset replacement.

It is notable however that Nutall Consulting's review found that UED's capital governance and practices were "well-evolved and fit-for-purpose", and had been developed in accordance with PAS 55:200811, a Publicly Available Specification that was developed in response to demand from industry for a standard relating to asset management in infrastructure intensive industries.

Table E5 below shows a comparison of the capital expenditure forecasts contained in UED's original Regulatory Proposal and those contained in the Draft Decision.

Table E5: Comparison of UED's original capital expenditure forecasts and Draft Decision (2010 dollars)

	YEAR ENDING 31 DECEMBER					Total ($ million)
	2011	2012	2013	2014	2015	
UED's original Regulatory Proposal	179.5	169.3	164.9	148.5	127.8	790.8
Draft Decision	107.9	107.3	102.6	106.2	107.7	531.5

UED is very concerned that the AER's Draft Decision provides an unrealistically low allowance for capital expenditure for the forthcoming regulatory period. It should be clearly understood that reducing UED's capital expenditure by approximately $260 million or 33 percent will have serious consequences for network reliability and UED's ability to comply with mandatory obligations in the forthcoming and subsequent regulatory periods.

In broad terms, the AER's Draft Decision relies on:

- a critique of the Victorian distributors' previous capital expenditure patterns, which the AER contends demonstrates a systematic bias in the distributors' forecasting methodologies;

- trend analyses of historic capital expenditure, but excluding data for 2009 and 2010, to provide an assessment of efficient capital expenditure for the forthcoming regulatory period;

- a replacement cost model, referred to as the repex model, developed by Nuttall Consulting. This model is calibrated to historic levels of replacement capital expenditure, and therefore implicitly assumes that this provides a reasonable basis for future expenditure levels. This unorthodox approach has not been employed in other AER determinations, which raises the question as to whether the AER is adopting an appropriately consistent approach to its application of the Rules;

- a "probabilistic" approach for reinforcement capital expenditure, developed by Nuttall Consulting, which estimates the probability that UED's reinforcement projects will be delivered in the forthcoming regulatory period. The estimated probability is based on Nuttall Consulting's subjective assessment of sample of six UED projects which is applied to determine the expenditure allowance for the entire capital program.

The AER and Nuttall Consulting have also criticised UED's forecasts in relation to the following matters:

- The AER raised concerns about the accuracy of the peak demand, energy consumption and customer number forecast used as a basis for reinforcement capital expenditure. The AER was critical of the lack of consistency between UED's bottom up forecasts and the top down forecasts produced by NIEIR.

- UED uses a 10 per cent probability of exceedence (POE) rather that a 50 per cent POE forecast of peak demand. Nuttall Consulting argued that if a 50 per cent POE demand forecast was used instead, the timing of network reinforcement projects would be affected, and projects could be deferred by up to three years.

- Nuttall Consulting argued that, as all projects did not have detailed business cases prepared, there was some likelihood that synergies and optimisation will be identified during the capital governance process that will result in a reduction of expenditure.

- In relation to IT capital expenditure, Nuttall Consulting observed that many of the distributors' strategy documents did not discuss or mention 'agility' or the intention to provide their business with a flexible architecture, such as 'cloud computing' that would be able to respond to the changing needs to the business. On this basis, Nuttall Consulting proposed a significant reduction in UED's IT capital expenditure forecast.

UED is very concerned that Nuttall Consulting's approach to assessing UED's capital expenditure is inconsistent with good industry practice. In particular, although Nuttall Consulting has concluded correctly that UED's planning and governance processes are well developed and fit for purpose, Nutall Consulting also considers that these processes cannot be relied upon to deliver efficient and prudent capital expenditure forecasts. Based on the results of the Nutall Consulting review of UED's capital expenditure governance, the AER should have confidence that UED has asset management processes and strategies in place to ensure that network services are delivered efficiently and prudently.

Furthermore, Nuttall Consulting has also resisted a detailed examination of UED's capital expenditure plans. Instead, the review approach has relied on:

- a general proposition that historic capital expenditure provides a good guide to future requirements;
- an assertion that as plans progress through the capital approval process an overall saving will be achieved;
- a simplistic replacement capital expenditure spreadsheet which does not reflect standard asset lives, but instead adopts the asset lives implied by recent expenditure levels; and
- an approach to reinforcement capital expenditure which assumes that any proposed capital expenditure can be reduced by at least 10%.

UED's original Regulatory Proposal provided very detailed information to explain and substantiate its capital expenditure forecasts. This Revised Regulatory Proposal provides further detailed substantiation to explain its capital expenditure forecast and to respond to the issues raised in the Draft Decision. UED cannot accept the AER's reliance on trend analysis.

In relation to RQM capital expenditure, forecasts based primarily on historical expenditure cannot account for the changing condition of the assets or changing performance of the network. For this reason trend analysis is unlikely to deliver a capital expenditure forecast consistent with the Rules requirements.

For RQM capital expenditure, UED explains that it uses a bottom up approach based on coherent, reasonable and prudent asset management systems. UED's systems require consideration of the condition of each asset type and, the most practical and cost effective way of estimating the amount of work required to maintain acceptable levels of performance of the network as a whole. This approach is consistent with good industry practice, and is vastly superior to the trend approach adopted by Nuttall Consulting and the AER.

As noted in detail below, UED has undertaken further work to revise forecast energy, maximum demand and customer numbers based on the latest (2009) available data, taking into account the revised AMI schedule, GDP growth, the latest summer peak demand data and revised air conditioner sales data. In addition, a reconciliation has been prepared between NIEIR's top down estimates and UED's bottom-up estimates and UED's view on diversity factors.

Overall, this work confirms that the maximum demand and energy volume forecasts have both increased slightly from UED's original Regulatory Proposal. The overall effect of these changes has been to bring forward slightly the proposed capex program, but otherwise the cost of the program has not been materially affected.

In relation to reinforcement capital expenditure, UED notes that its list of reinforcement projects has been developed following a well proven and sophisticated assessment process, considering load growth, utilisation, plant loading and customer load at risk. By contrast, Nuttall Consulting's approach is overly simplistic and appears to be without factual support, except for a comparison with historical expenditure.

The probabilities used by Nuttall Consulting in assessing UED's projects appear to be totally subjective and without basis. For example, the highest probability weighting allowed under Nuttall Consulting's approach is 90 percent, which means that the total proposed capital expenditure for reinforcement projects will always be reduced by at least 10 percent. Clearly, this is a biased forecasting methodology because it cannot lead to the AER's acceptance of 100% of the proposed expenditure, even in cases where the forecast is inadequately low.

In relation to IT capital expenditure, UED does not accept Nuttall Consulting's criticisms. For example, whilst cloud computing services are becoming increasingly common for commodity IT services (e.g. email), they are not common for business-critical systems such as SCADA, Oracle NMS, and GE Smallworld. There is no experience of electricity distribution utilities using cloud computing services for delivering core business applications. Nuttall Consulting is therefore incorrect in suggesting that UED's IT strategy is deficient in this regard.

UED considers that the approach adopted by the AER and its advisers (Nutall Consulting) in the assessment of UED's capital expenditure forecasts fails to accord with the requirements of the Rules. Moreover, the approach adopted in the Victorian Draft Decision is novel and it differs markedly from the approach adopted in other AER decisions, in that:

- it places undue reliance on historical actual expenditure to determine forecast capital investment requirements;
- it rejects best-practice approaches to capital expenditure forecasting, such as bottom-up planning; and

- it does not properly take into account the forward-looking drivers of capital investment, such as asset condition.

As noted above, and as demonstrated in detail in this Revised Regulatory Proposal, the AER's approach has led it to adopt a capital expenditure forecast for UED that is insufficient to enable the company to achieve the capital expenditure objectives set out in the Rules. UED's capital expenditure forecasts, on the other hand, have been fully substantiated and supported by independent expert opinions.

More broadly, UED is concerned that the approach adopted by the AER in the Victorian Draft Decision, if upheld, will severely damage incentives for efficient investment. Under the AER's new approach to using historic levels of capital expenditure to inform decisions about future allowances, DNSPs will have no incentives to invest efficiently:

- A DNSP that efficiently defers capital expenditure in one period will face a reduced capital expenditure allowance in subsequent periods.

- On the other hand, a DNSP that over-invests will be rewarded with increasing future capital expenditure allowances.

The diminution of efficient investment incentives in this way would be strongly inconsistent with the National Electricity Objective.

UED urges the AER to reconsider its assessment of UED's capital expenditure requirements. UED has fully substantiated its capital expenditure forecasts in accordance with the requirements of the Rules, and the proposed forecast reasonably reflects the efficient and prudent costs of achieving the capital expenditure objectives. Therefore, in accordance with the provisions set out in clause 6.5.7 of the Rules, the AER must accept UED's capital expenditure forecasts.

UED's capital expenditure forecasts are summarised in the table below.

Table E6: UED's revised capital expenditure forecasts for standard control services (2010 dollars)

	YEAR ENDING 31 DECEMBER					Total $M
	2011	2012	2013	2014	2015	
SYSTEM ASSETS						
Reinforcements	45.0	48.2	49.5	40.9	30.4	214.0
Customer initiated	53.4	51.8	50.1	49.0	47.3	251.7
Reliability & Quality Maintained	61.8	58.9	57.1	50.8	51.8	280.3
Reliability & Quality Improvements	0.0	0.0	0.0	0.0	0.0	0.0
Environmental, Safety & Legal	22.4	15.5	13.1	9.8	9.3	70.1
Sub-total system assets	**182.6**	**174.4**	**169.8**	**150.6**	**138.8**	**816.1**
NON-NETWORK ASSETS						
Non-Network General Assets – IT	23.5	36.5	27.6	16.0	7.2	110.9
SCADA and network control	0.0	0.7	3.9	0.0	0.0	4.7

	YEAR ENDING 31 DECEMBER					Total $M
	2011	2012	2013	2014	2015	
Non-Network Gen. Assets – Other	8.8	4.3	2.5	2.8	2.5	20.9
Sub-total non-network assets	**32.3**	**41.5**	**34.0**	**18.8**	**9.8**	**136.5**
Total capital expenditure	**214.9**	**215.2**	**200.0**	**169.4**	**148.5**	**952.6**
Less – Customer contributions	27.7	27.0	26.5	26.8	26.0	134.0
NET CAPITAL EXPENDITURE	**187.2**	**188.2**	**173.5**	**142.6**	**122.5**	**818.6**

Amounts shown in real 2010 terms.

Cost of capital

UED's original Regulatory Proposal noted that the provision of an adequate return on capital is of critical importance to UED's owners and its customers. An inadequate allowance for the cost of capital will make it extremely difficult for UED to compete for its required share of funding, which in turn will have adverse implications for the long term interests of consumers.

UED's original Regulatory Proposal adopted the parameter values and methodologies set out in the Rules and the applicable statement of regulatory intent (SORI) with the exception of the values for the market risk premium (MRP) and the value of imputation credits (gamma). In the case of these two parameters, UED's original Regulatory Proposal considered that there is persuasive evidence available to justify a departure from the values specified in the SORI. UED proposed a value of 8 per cent for the MRP, and a value of 0.5 for the gamma.

In the Draft Decision:

- The AER rejected the proposed MRP of 8 per cent, on the basis that the Victorian DNSPs' proposals did not constitute persuasive evidence to depart from the value of 6.5 per cent specified in the SORI. The AER commented that a "MRP of 6.5 per cent may be considered conservative when accounting for current prevailing conditions".

- The AER rejected UED's proposed gamma value of 0.5 and instead adopted a value of 0.65.

- The AER also rejected UED's proposed estimate of the debt risk premium.

The table on the following page summarises UED's revised WACC in response to the Draft Decision.

Table E7: UED's revised WACC and corporate tax allowance proposal

Parameter	Value adopted in this Revised Regulatory Proposal	Basis for the adoption of this value by UED
Nominal risk free rate	5.65%	This value has been determined in accordance with the method specified in the SORI.
Equity beta	0.80	This value is as specified in the SORI.
Market risk premium	6.5%	Comments made by the Reserve Bank Governor in June of this year, together with updated empirical analysis presented by Bishop and Officer point to on-going uncertainty regarding the outlook for the global economy and financial markets, and on-going levels of volatility in financial markets that are well above average. This most recent evidence does not support the AER's contention that "a MRP of 6.5 per cent may be considered conservative when accounting for current prevailing conditions." UED considers that the latest available evidence continues to support the application of an MRP value of no less than the value specified in the SORI. For the purpose of this Revised Regulatory Proposal, UED has adopted an MRP value of 6.5%.
Gearing	0.60	This value is as specified in the SORI.
Debt risk premium	428 basis points	Based on independent expert advice provided by PriceWaterhouse Coopers and CEG.
Gamma	0.2	UED has obtained further independent advice from Strategic Finance Group (SFG) and Dr Neville Hathaway that constitutes persuasive evidence for adoption of a gamma value of 0.2. The comprehensive dividend drop-off study undertaken by SFG shows that an appropriate estimate of theta is 0.24. On the basis of Dr Hathaway's analysis, UED has adopted a payout ratio of 69%. Combining these two constituent variables gives an overall gamma value of 0.17, which has been rounded to 0.2 for the purpose of this Revised Regulatory Proposal.

S-factor close-out

In the current regulatory period, UED has been subject to an S-factor performance incentive mechanism in accordance with the ESCV's determination. The AER's framework and approach paper noted the AER's intention to give effect to the ESCV's S-factor scheme by including appropriate amounts in the building block calculation for the forthcoming regulatory period.

However, the ESCV's S-factor scheme was not designed to be closed out. Although UED previously pointed out to the ESCV that its scheme may deliver unanticipated outcomes, UED's concerns were rejected by the ESCV. The AER's attempt to close out the ESCV's scheme demonstrates that UED's observations were correct.

The AER's S-factor close-out mechanism imposes a penalty on UED of approximately $102 million, which is a massive and unexpected penalty, especially as UED's network performance has never been the subject of any particular criticism, scrutiny or concern on the part of the AER. UED's original Regulatory Proposal used the same data, but an alternative mathematical formulation for the close-out. UED's formulation derived a penalty of approximately $2 million upon cessation of the S-factor scheme.

The $100 million difference between calculations undertaken by UED in its original Regulatory Proposal and those of the AER, using the same data but based on alternative mathematical formulations, illustrates the problems with a mathematical close out of the ESCV's scheme. UED's view is that a mathematical solution to closing out the S-factor scheme should no longer be pursued. The incentives on distributors vary widely between the alternative formulations and are considered to be severely distorted under the AER's mechanism.

Notwithstanding UED's view, it should be noted that UED's latest forecast for 2010 performance is substantially improved from the estimate presented in the original Regulatory Proposal. As a result, the application of the AER's close out mechanism would most likely require a payout by UED of $11.6 million in NPV terms, expressed in 2010 prices. It should also be noted that application of UED's close-out formulation – which has superior incentive properties compared to the AER's close-out mechanism - would likely result in no penalty being paid.

As already noted, UED considers that a mathematical solution to closing out the S-factor scheme should no longer be pursued. Instead, the S-factor scheme should simply stop and no carryover amount should be included in the building blocks. This is consistent with the National Electricity Objective and the National Electricity Law.

Depreciation

In its original Regulatory Proposal, UED explained that it had prepared its depreciation forecast for the forthcoming regulatory control period by applying forecast asset additions, forecast asset disposals, asset lives and the AER's roll forward model in accordance with Rules requirements.

The AER's Draft Decision argued that:

- UED had proposed an accelerated depreciation of its sub transmission and distribution assets.

- The AER considers that a better way for UED to address this issue is to make adjustments to the remaining lives of assets. The AER considers that this is the appropriate method to address instances of assets having residual value for regulatory purposes at the time they are replaced.

UED believes that the AER has misinterpreted UED's approach, and as such we seek to correct that misunderstanding. The accelerated depreciation approach originally proposed by UED was necessitated by specific capital replacement programs. The assets that will be affected by UED's planned replacement programs have now been identified in a separate asset class. UED notes that this approach accords with the principles outlined in the AER's Draft Decision by ensuring that the residual value of assets is recovered at the time they are replaced. In addition, UED's approach also ensures that assets that are planned to be replaced over the course of the next regulatory period will be appropriately accounted for in the regulatory asset base.

Demand and energy forecasts

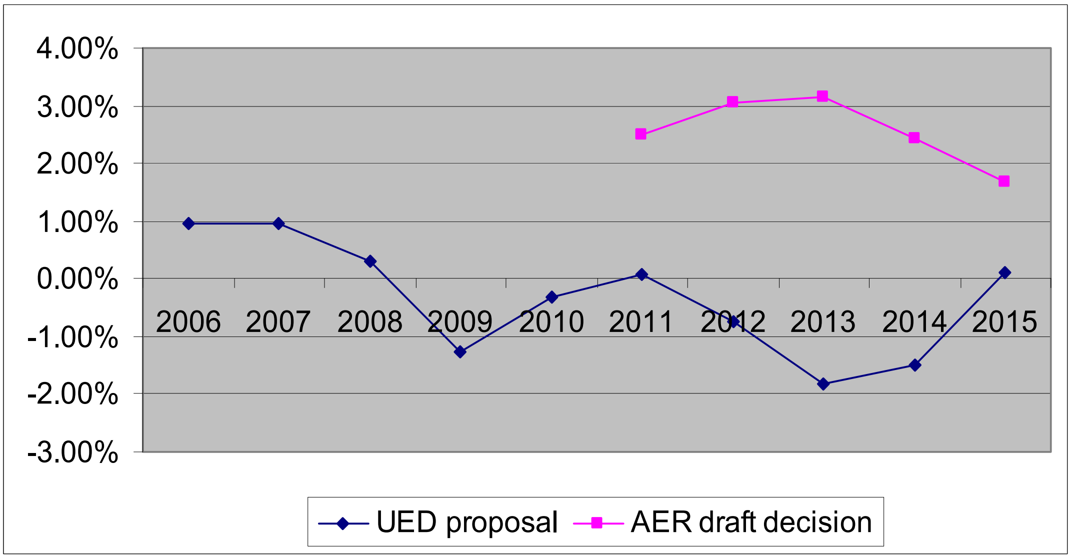
The AER's Draft Decision states that:

- UED's maximum demand forecasts for the forthcoming regulatory period are generally consistent with historic trends.
- On balance NIEIR's maximum demand forecasting methodology appears to be reasonable.
- NIEIR's approach to forecasting energy exhibits elements of good forecasting methodology although it lacks transparency.
- UED's forecasts were out of date at the time of the Draft Decision, and a new forecast should be provided as part of UED's revised proposal.

The Draft Decision also noted that the AER made post modelling adjustments to UED's forecast to reflect the impacts of population growth; MEPS; CPRS; the AER's belief that it is unreasonable to assume any impact arising from the AMI roll-out in the forthcoming regulatory control period; and other initiatives and schemes.

We think the AER does not fully understand the very significant and spurious impacts that their adjustments have made to UED's energy forecasts. The figure below highlights the problem.

Figure E7: Comparison of UED's original energy volume growth forecast and the Draft Decision



The above figure highlights the following facts:

- Historically, growth in UED's energy sales volumes has been very low and stable. Different distributors are typically in the range of 0 to 2 percent per annum, but UED has averaged a little more than 0% over the last 5 years.

- The AER's forecast assumes that UED's growth will jump to 2.6 percent per annum, even though electricity customers and Governments are making every effort to reduce energy usage in response to climate change.

- The figure shows the discontinuity between UED's historic growth and the AER's forecasts. It clearly shows that UED's forecast is much more consistent with historic trends.

In this Revised Regulatory Proposal, UED explains that the forecast methodology and the forecasts proposed by UED are practical and prudent for a capital-intensive business and they incorporate a reasonable approach to assessment and quantification of uncertainty and risk as part of UED's normal business planning processes.

UED's forecasts utilise output from NIEIR's modelling that incorporate reasonable assumptions, including assumptions that reflect the substantial changes in Government policy since 2005 that are explicitly intended to reduce energy consumption in all sectors of the economy.

Both the Australian and Victorian Governments have stated publicly that they are either adopting new policies or modifying existing policies with a specific intention of achieving even more substantial energy efficiency improvements in the economy; and both Governments are reviewing other existing policies with the intention of contributing to that same objective within the next regulatory period.

Each of the existing policies, and the announced changes to policy, are supported by Regulatory Impact Statements (RIS) conducted in compliance with Council of Australian Governments (COAG) *Best Practice Regulation Guide*. Each of these RISs presents an estimate of the expected energy reductions. The cumulative RIS estimates of energy savings are material and were intended to impact on energy consumption in the 2005-10 period. Confirmed policy changes, and others where reviews have been confirmed by Governments are intended to intensify those impacts in the 2010-15 period and beyond.

Given these circumstances, it is incongruous for the AER to assume the suite of energy efficiency policies implemented by COAG and the Victorian Government will have only a minor impact on energy consumption for customers connected to UED's distribution network.

Analysis contained in this Revised Regulatory Proposal demonstrates that the post modelling adjustments made by the AER are incorrect. UED has provided details of more appropriate and reasonable adjustments.

UED has also engaged NIEIR to provide a set of updated forecasts to reflect the latest economic conditions. The forecasts provided by UED in this Revised Regulatory Proposal reconcile to the latest AEMO forecasts. The revised forecasts confirm that UED's energy volumes over the forthcoming regulatory period are expected to decline, at an average rate of 0.4 per cent per annum, slightly lower than NIEIR's initial forecast.

UED accepts that, like all forecasts, its revised forecasts contain elements of uncertainty. Energy volumes could be significantly higher than NIEIR's forecasts if consumers seek higher levels of service and comfort than assumed in the respective RISs. Energy volumes could also be significantly lower than this forecast if:

- NIEIR's assumptions about the effectiveness of the suite of energy efficiency policies prove to be too modest (e.g. builders and home owners voluntarily adopt energy efficiency measures that exceed mandatory standards);

- consumers respond to continuing public messages reinforcing the environmental and cost reduction benefits of energy efficiency policies (and mirror outcomes in the water sector where consistent messages promoting the benefits of water savings demonstrate strong resilience); and

- due to impacts of further or modified energy efficiency policies that have been announced but are not included in NIEIR's modelling.

UED's revised forecasts also confirm that peak summer demand will continue to grow at a substantially higher rate than energy consumption, primarily due to continued increases in air conditioning penetration in the residential sector, and UED's forecast customer number growth rate, which is less than Victoria's population growth rate.

UED's revised revenue and price outcomes for customers

In light of UED's response to the Draft Decision, the tables below show:

- UED's revised proposed increase in average prices for the forthcoming regulatory period; and

- the principal reasons for the proposed increases.

Table E8: UED's revised real price increases for the forthcoming regulatory period

2011	2012	2013	2014	2015
16.83%	4.0%	4.0%	4.0%	4.0%

Table E9: Principal reasons for UED's real price increases

Building block	Price change effect	Discussion
Return on capital	Approximately 9%	The cost of capital in this proposal is 7.53% compared to current WACC of 5.90%. The increase is driven primarily by a higher debt risk premium, reflecting market conditions.
Operating expenditure	Approximately 7%	The increase in driven by the additional volume of work, including new obligations.

In considering the impact of UED's proposals on end customers, it is important to recognise that a typical electricity bill will comprise 4 components. These are:

- the cost of wholesale electricity (generation);
- the cost of bulk transportation (transmission);
- the cost of distribution (distribution); and
- billing (retail costs).

This Revised Regulatory Proposal only relates to the distribution component of an electricity invoice. An analysis of the impact of UED's proposals on the total cost of electricity delivered to a typical residential consumer is provided in E10 below:

Table E10: Analysis of impact of UED's Revised Regulatory Proposal on a typical residential bill

	Current invoice (2010)	New invoice (2011)	% Change
Generation	$200.00	$200.00	0.0%
Transportation	$100.00	$100.00	0.0%
Distribution	$290.00	$338.00	16.8%
Retail	$360.00	$360.00	0.0%
AIMRO	$70.00	$70.00	0.0%
Total Invoice	**$1,020.00**	**$1,068.00**	**4.7%**

Amounts shown in real 2010 terms.

1. Introduction and structure

United Energy Distribution (UED) is one of five electricity distribution businesses operating under licence within the State of Victoria. UED manages network assets with a replacement value of approximately $3.7 billion, comprising 45 zone substations, approximately 208,000 poles, 11,500 distribution substations, 10,000 km of overhead power lines and 2,300 km of underground cables. UED's electricity distribution network provides services to almost 630,000 end-use customers, located in an area of 1,472 km^2 in south-east Melbourne and the Mornington Peninsula. UED's distribution area is shown in Figure 1-1 below.

Figure 1-1: UED Distribution Territory

The regulatory arrangements applicable to UED changed on 1 January 2009, when the AER assumed responsibility for the economic regulation of electricity distribution networks in Victoria. In accordance with the National Electricity Rules (the Rules), UED submitted its original Regulatory Proposal on 30 November 2009. UED's original Regulatory Proposal explained and substantiated the company's proposed price-service package for the period from 1 January 2011 to 31 December 2015.

The AER published its Draft Decision on UED's Regulatory Proposal on 31 May 2010. Clause 6.10.3 of the Rules provides UED with 30 business days to prepare and submit a Revised Regulatory Proposal. UED is also required to comply with the AER's Urgent Regulatory Information Notice, which was issued on 31 May 2010.

UED has structured this Revised Regulatory Proposal to focus specifically on the matters raised by the AER in its Draft Decision. This submission does not repeat information or analysis previously submitted by UED, unless it is relevant to a particular issue arising from the Draft Decision. For the avoidance of doubt, it is noted that UED's original Regulatory Proposal – varied in accordance with this Revised Regulatory Proposal - forms part of this Revised Regulatory Proposal.

To assist stakeholders, this Revised Regulatory Proposal provides context to each issue by recapping and cross-referring to UED's original Regulatory Proposal. UED notes that stakeholders continue to have access to UED's original Regulatory Proposal via the AER's or UED's websites, if stakeholders wish to refer to the source documents.

To further assist stakeholders and the AER, this Revised Regulatory Proposal adopts the same chapter structure as UED's original Regulatory Proposal. This approach not only facilitates the cross-referencing to the original Regulatory Proposal, but it also provides comfort that the Revised Regulatory Proposal provides a comprehensive picture of UED's revised expenditure and service plans following the Draft Decision. The remainder of UED's Revised Regulatory Proposal is therefore structured as follows:

- Chapter 2 recaps briefly on UED's current performance and service performance under the ESC's S-factor scheme, and the AER's comments on UED's performance in the AER's Draft Decision.
- Chapter 3 recaps briefly on UED's management and Board decision to adopt its new business model. UED also responds to the AER's comments regarding the competitiveness of UED's tender process for outsourced services.
- Chapter 4 addresses the AER's Draft Decision on customer demand and UED's compliance obligations, which affect UED's expenditure plans for the forthcoming regulatory period.
- Chapters 5 to 11 respond to the AER's Draft Decision in relation to each regulatory building block element that together comprise UED's revenue requirements. For each element, UED responds to the issues raised by the AER in its Draft Decision.
    - Chapter 5 addresses operating expenditure plans and forecasts;
    - Chapter 6 addresses capital expenditure plans and forecasts.
    - Chapter 7 addresses depreciation.
    - Chapter 8 addresses the regulatory asset base.
    - Chapter 9 addresses the cost of capital.
    - Chapter 10 addresses the 'other building block elements' - namely, UED's entitlements to revenue for the forthcoming regulatory period flowing from the operation of the S-factor scheme and efficiency carry-over mechanism during the current period.
    - Chapter 11 revisits the total revenue and X factor calculation in light of the AER's Draft Decision and UED's response as set out in chapters 5-10.
- Chapter 12 addresses the AER's Draft Decision on UED's proposed classification of distribution services.
- Chapter 13 addresses the AER's Draft Decision on UED's energy, peak demand and customer number forecasts.
- Chapter 14 addresses the AER's Draft Decision on UED's proposed tariff strategy.
- Chapter 15 addresses the AER's Draft Decisionon UED's proposed control mechanisms for standard control services and alternative control services.

- Chapter 16 addresses the AER's Draft Decision on UED's proposed application of the service target performance incentive scheme.
- Chapter 17 addresses the AER's Draft Decision on UED's proposed application of the efficiency benefit sharing scheme for the forthcoming regulatory period.
- Chapter 18 addresses the AER's Draft Decision on UED's proposed application of the demand management incentive scheme for the forthcoming regulatory period.
- Chapter 19 addresses the AER's Draft Decision on UED's proposed pass through events.
- Chapter 20 addresses the AER's Draft Decision on UED's negotiating framework
- Chapter 21 addresses the AER's Draft Decision on UED's Alternative Control
- Chapter 22 addresses the AER's Draft Decision on UED's Public Lighting

2. Background: UED's efficient performance

Key messages

UED's original Regulatory Proposal explained that:

- UED has delivered substantial cost reductions, price reductions and service improvements since its establishment in 1995. The achievements delivered to date by UED accord strongly with the National Electricity Objective and the Rules.
- The Victorian distributors have achieved substantially greater efficiency benefits than their peers, especially in New South Wales and Queensland. Benchmarking demonstrates that UED is already an efficient service provider and is expected to remain an efficient, low cost performer. On network performance, UED explained that it had not been able to sustain the record high level of network reliability performance it achieved in 2004.

In its Draft Decision, the AER commented that on the basis of its top down and bottom up analysis, Victorian DNSPs appear relatively efficient compared to other non-Victorian DNSPs.

In this Revised Regulatory Proposal UED notes that:

- The AER has not considered the price benchmarking presented by UED in its original Regulatory Proposal, which shows UED to be the lowest cost performer across the 12 distribution businesses in the National Electricity Market. A recent paper by Bruce Mountain and Professor Stephen Littlechild uses the same benchmark measure to conclude that Victorian distributors are superior cost performers compared to the NSW distributors.
- A price comparison calculated from the AER's Draft Decision illustrates that the AER's Draft Decision is out-of-step with its recent determinations in NSW and Queensland. It is also out-of-step with the commercial realities facing UED. The AER has established clear precedents – in terms of the meaning of efficient and prudent expenditure forecasts under the Rules - by adopting the expenditure forecasts that it has in NSW and Queensland. The AER must consider these precedents when it examines the efficiency and prudency of UED's expenditure forecasts.
- UED contends that the inconsistency and randomness in the AER's consideration of efficiency does not promote effective incentives or economic efficiency, as required by the Revenue and Pricing Principles in the National Electricity Law.
- UED is concerned that the approach adopted by the AER in the Victorian Draft Decision, if implemented, will undermine incentives for efficient investment in and operation of networks, contrary to the requirements of the National Electricity Law and the Rules. This is because the AER's reliance on "revealed" costs to set expenditure allowances in future periods rewards and reinforces mediocrity and inefficient performance, whilst penalising – through the provision of reduced expenditure allowances – companies that innovate and deliver efficiency improvements.

- A proper application of the Revenue and Pricing Principles in the National Electricity Law requires that incentive-based regulation should reward, not penalise, those distribution companies that have delivered cost savings for customers.
- The Rules require UED to provide forecasts of operating and capital expenditure (respectively). UED considers that the AER's rejection of UED's forecasts, and the adoption of an approach of "projecting" UED's recent actual costs to derive expenditure allowances for the purpose of the Draft Decision fails to meet the requirements of the Rules. Further detailed analysis of the AER's approach to assessing UED's operating and capital expenditure forecasts are presented in Chapters 5 and 6 respectively.
- An independent expert opinion from Philip Williams of Frontier Economics comments that he finds it odd that the AER has rejected UED's operating expenditure forecast as not reflecting efficient and prudent costs.

2.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal explained that the concept of efficiency is embodied in the national electricity objective and Chapter 6 of the Rules. UED noted that the efficiency of its recent cost and service performance – benchmarked against its Australian peers – is relevant to the AER's review of UED's expenditure forecasts. Specifically, in deciding whether or not the AER is satisfied that the total of the forecast operating expenditure reasonably reflects efficient costs, clause 6.5.6(e) requires the AER to have regard to a number of "operating expenditure factors", including:

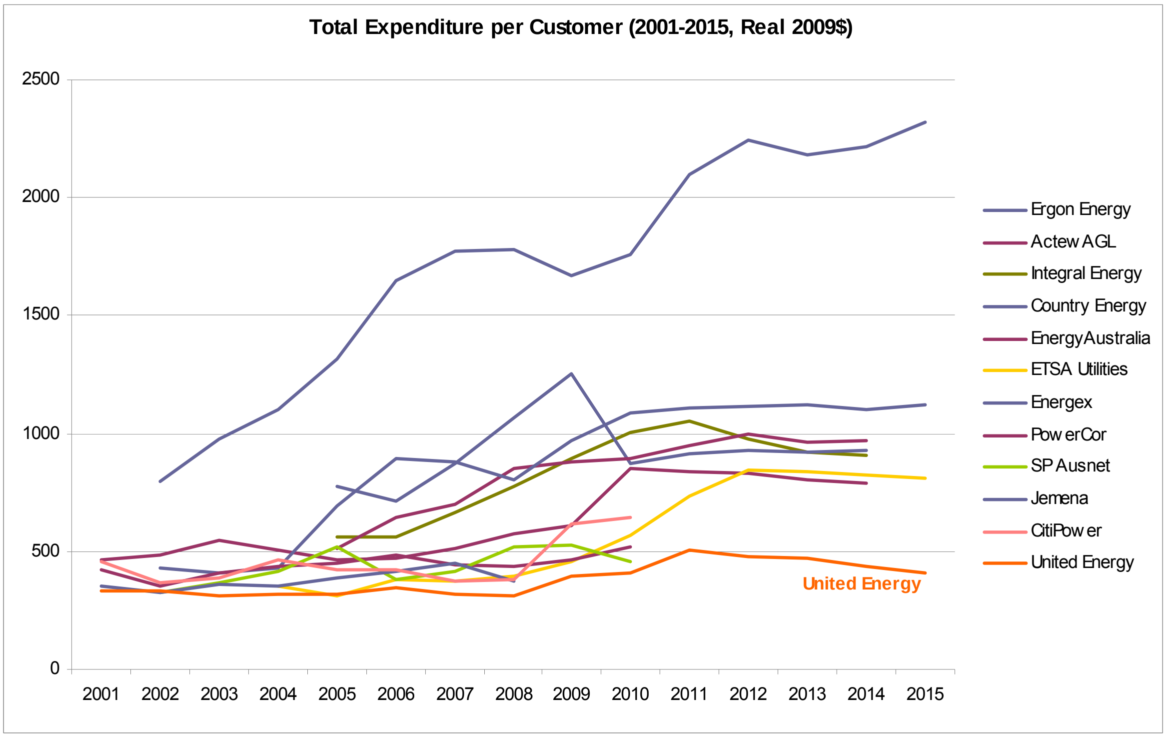
(1) benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period; and

(2) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods.

UED's original Regulatory Proposal explained that since its formation in 1995, UED's distribution charges to a typical domestic customer are now 39 per cent lower than in 1995. In 2003, UED aggressively extended its use of an outsourcing business model service, as a mechanism for driving efficiencies.

In contrast to largely in-sourced business models adopted by network businesses in other States, UED (and the other privatised Victorian Distribution Businesses) have delivered substantially greater efficiency benefits. UED's comparative performance has been assessed through benchmarking studies. Figure 2-1 shows the time series data for total expenditure per customer.

Figure 2-1: Comparison of total expenditure per customer for distribution companies



Source: SKM DNSP Benchmarking Measures.

UED's original Regulatory Proposal provided alternative benchmark measures of its cost performance, each of which reinforced the conclusion that UED's performance is superior to its peers in other states.

UED commented that NSW distribution businesses will increase their network charges by an average of 52 per cent over their forthcoming regulatory period, effectively producing price levels that exceed 1997 levels in real terms, establishing new price levels by 2014 some 31.5 per cent higher than they were in 1997. This compares to the prices being put forward by UED in its original Regulatory Proposal for the forthcoming regulatory period, which will still be some 17 per cent lower in real terms in 2014 compared to 1997. The combined effect of the NSW price increases between 1997 and 2014 and UED's price reductions is a 39 per cent price differential in favour of UED's customers over the period[4].

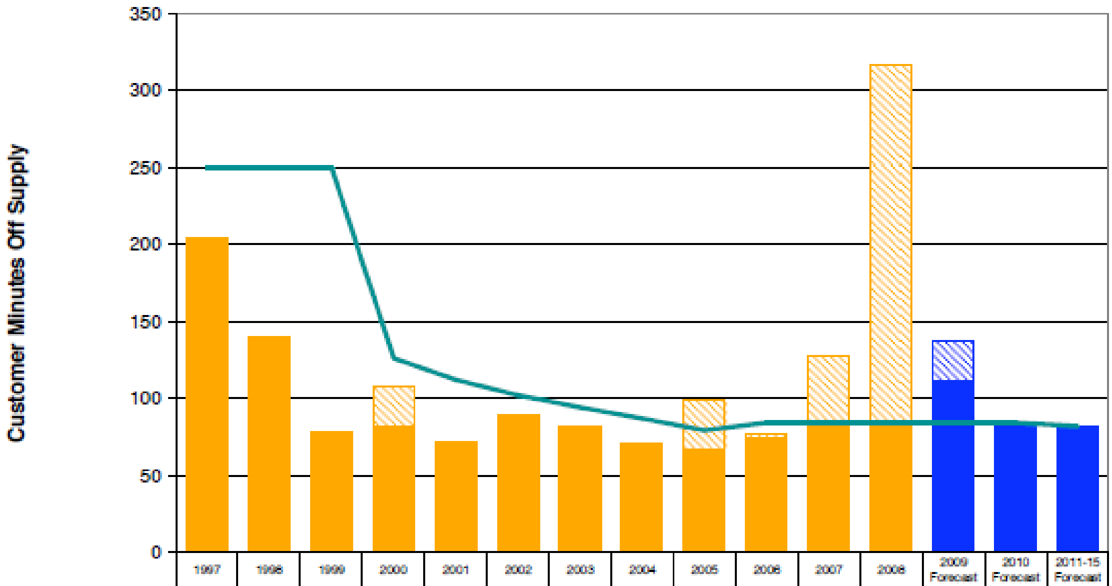
UED commented that competitive neutrality is a long-standing principle which means that State-owned and privatised enterprises should be afforded a level playing field. In terms of economic regulation, this principle means that the AER should not apply a higher standard of efficiency to the privatised Victorian businesses because of their performance is superior to distributors in other states.

In terms of service performance, UED's original Regulatory Proposal explained that its capital and maintenance programs have consistently focused on improving the level of

[4] AER, NSW distribution determination 2009/2010 – 2013/14, 28 April 2009, approved cumulative X factor increases of 31 per cent for Integral Energy and larger increases for the other NSW businesses.

supply reliability to customers. Figure 2-2 below shows that UED delivered very substantial improvements in SAIDI from 1998-2005.

Figure 2-2: Actual and regulatory benchmark minutes off supply per customer



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 Forecast	2010 Forecast	2011-15 Forecast
Excluded Events				25					31	1	44	233	26		
United Energy	205	139	78	82	72	89	82	70	67	75	84	84	111	84	82
Reg. SAIDI target	250	250	250	126	112	102	94	87	79	84	84	84	84	84	82

UED's original Regulatory Proposal explained that modelling simulations conducted in 2005[5] showed that the reliability enjoyed by UED's customers in 2004 and 2005 was at an all-time high, particularly due to benign weather. Subsequent network performance has been adversely affected by increased storm activity and age-related deterioration in asset performance. The effects of climate change are expected to lead to an increase in the frequency and intensity of storms, as well as an increase in number and severity of hot days. As a result, UED's analysis indicated that there is very limited scope for further substantial reliability improvements to be delivered cost-effectively.

UED explained that its proposed capital expenditure program would maintain the present levels of reliability and quality, as well as ameliorate the forecast impact of worsening weather conditions on network reliability. UED proposed overall price increases for the 2011-2015 regulatory period, as summarised in Table 2-1 below. These price increases will be the first increase in real terms since UED's formation in 1995, and will lead to prices in 2015 that are 17 per cent lower in real terms compared to 1995.

UED also noted that the single largest contributing factor for this price increase relate to the cost of capital. Of the 16.6 per cent increase, 12.1 per cent is attributable to the cost of capital.

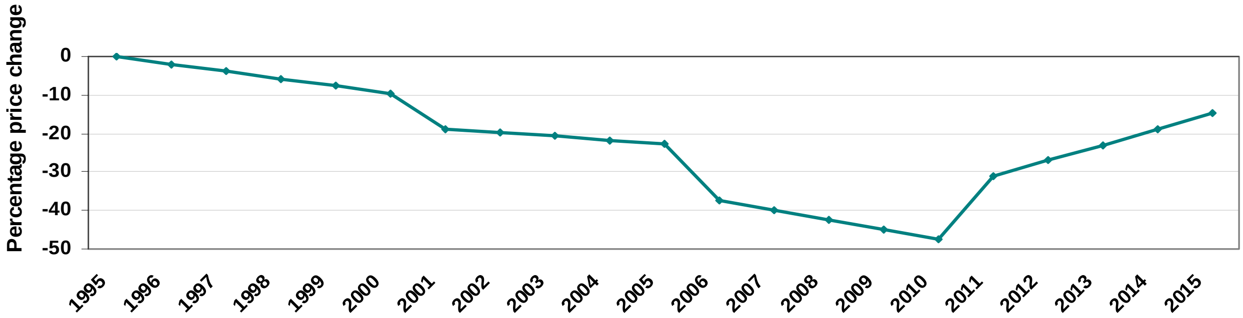
5 UED, Submission to the ESC re: Service Incentive Risk Issues Paper, 2 September 2005, page 9.

Table 2-1: Average price increase originally proposed over the 2011-2015 regulatory period

Category	2011	2012	2013	2014	2015
Set Price Change	-16.6%	-4.0%	-4.0%	-4.0%	-4.0%

The graph below Figure 2-3 shows the cumulative price changes since 1995.

Figure 2-3: Cumulative price changes, 1995 - 2015



The resulting effect of the above price path is that in the coming period United Energy customers will be asked to pay prices which are some 23 per cent (on average) lower, in real terms, than 1995 prices.

2.2 AER's Draft Decision on UED's cost and service performance

The Draft Decision does not comment on UED's analysis of its actual and forecast price path price compared the NSW distribution businesses.

Benchmarking analysis in provided in Appendix I, which compares the cost performance of the Victorian DNSPs and interstate DNSPs. The AER concluded, on the basis of its top down and bottom up analysis, that Victorian DNSPs appear relatively efficient compared to other non-Victorian DNSPs. The AER commented as follows[6]:

> "As noted above, in assessing DNSPs' proposals against the opex criteria, the AER has had regard to the opex factors including benchmarking (clause 6.5.6(e)(4) of the NER) and actual and expected opex (clause 6.5.6(e)(5) of the NER). Appendix I details the techniques the AER has applied in assessing the DNSP proposals, including the use of benchmarking and the trend analysis.
>
> The trend analysis, together with benchmarking the Victorian DNSPs against DNSPs in other jurisdictions, demonstrates that the Victorian DNSPs compare favourably to those in other states. This suggests that the revealed costs of the Victorian DNSPs are a sound base for determining the starting point for evaluating their forecast opex proposals.
>
> The AER considers that the Victorian DNSPs are subject to commercial incentives, both through their governance arrangements and the specific incentive mechanisms of the

6 AER, Draft Decision, pages 224 and 225.

regulatory framework. As noted in section 7.3.1, the Victorian DNSPs, during the current and previous regulatory control periods, have demonstrated that they continually outperform their opex regulatory benchmarks."

2.3 UED's response to the AER's Draft Decision

The ongoing integrity of the regulatory framework relies on consistent regulatory decision-making through time. The AER's approach to decision-making in the present Victorian distribution review – and in particular its approach to assessing the expenditure forecasts presented by the Victorian distributors – differs markedly from the approach and standard it has applied in previous decisions.

The impact of the AER's application of a new and unreasonably stringent approach in the Victorian Draft Decision is illustrated by an examination of outcomes in Victoria compared with New South Wales. This comparison is aided by a paper by Bruce Mountain and Professor Stephen Littlechild, which was published in December 2009 by the Electricity Policy Research Group of the University of Cambridge[7]. That paper presents an objective and an independent comparison of the cost and service performance of the electricity distributors in NSW and Victoria. Given the credentials of the authors, the paper is worthy of being accorded considerable weight. UED also notes that this paper has been strongly supported by the EUAA, a body that represents UED customers.

Pages 19 to 23 of the Mountain and Littlechild paper stated:

> "Peak demand in the Victorian power system has grown at a compound annual rate of 4.5% between 2002 and 2008 compared to 3.0% growth in NSW. Distributor customer numbers in Victoria have been growing at an annual average rate of 1.9%, roughly twice the rate in NSW. Quality of supply as measured by the frequency and duration of outages has consistently been better in Victoria than in NSW.
>
> These data suggest that, in terms of customer density, size of company and growth in demand, Victoria is faced with more demanding conditions as NSW, and has delivered better quality of service. If these factors are significant, this should lead to higher previous and projected costs and revenues in Victoria than in GB and also higher than in NSW.
>
> The evidence suggests that the first proposition is true but the second is not. Figure 6 shows that allowed annual revenue per customer in Victoria was indeed the highest of all three markets in 2000, and remained consistently higher than in GB. But over the decade from about 2000 to about 2010 it decreased by about 20% in Victoria whereas it increased by about 70% in NSW. By 2010 allowed annual revenue per customer in Victoria was around half the level in NSW.

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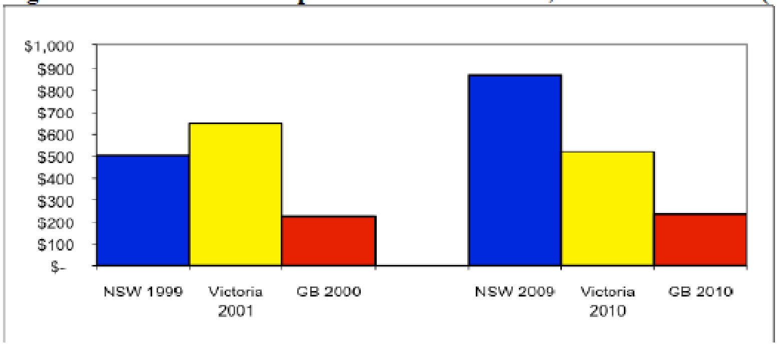
7 Bruce Mountain and Stephen Littlechild, Comparing electricity distribution network costs and revenues in New South Wales and Great Britain, EPRG Working Paper 0930, December 2009.

Figure 6 Annual revenue per customer in NSW, Victoria and GB (2008 AUD)



The same picture is reflected in the main components of allowed revenue. Figure 7 shows that, in the first regulatory period, allowed opex per customer was slightly higher in Victoria than in NSW, but from the first to the second period it fell in Victoria and rose in NSW, so that it was now about 25% lower in Victoria. Figure 8 shows that, in the first regulatory period, allowed capex per customer was about 60% higher in Victoria than in NSW, but then remained about constant whereas it increased sharply in NSW, so that in the second period it was about 10% lower in Victoria.

Figure 7 Allowed opex per customer in NSW, Victoria and GB (2008AUD)

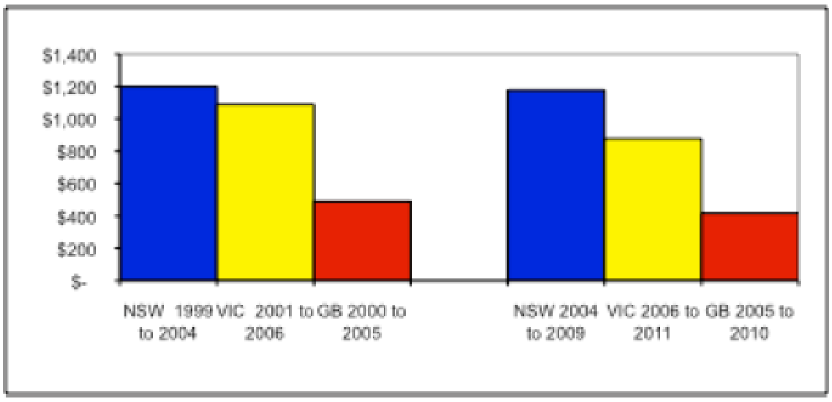
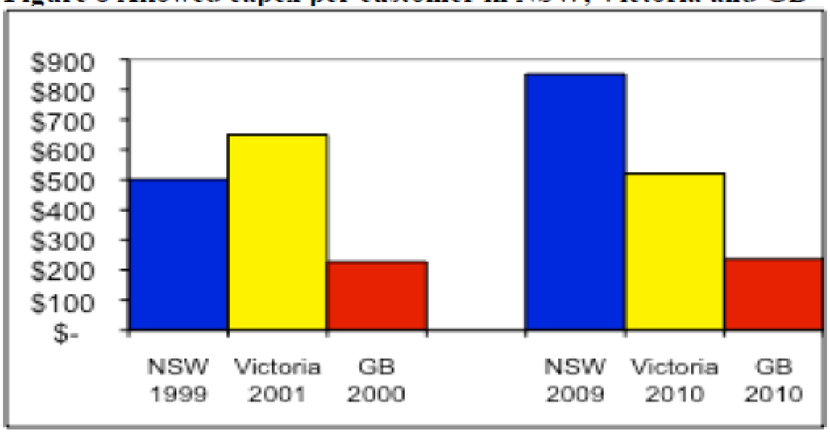
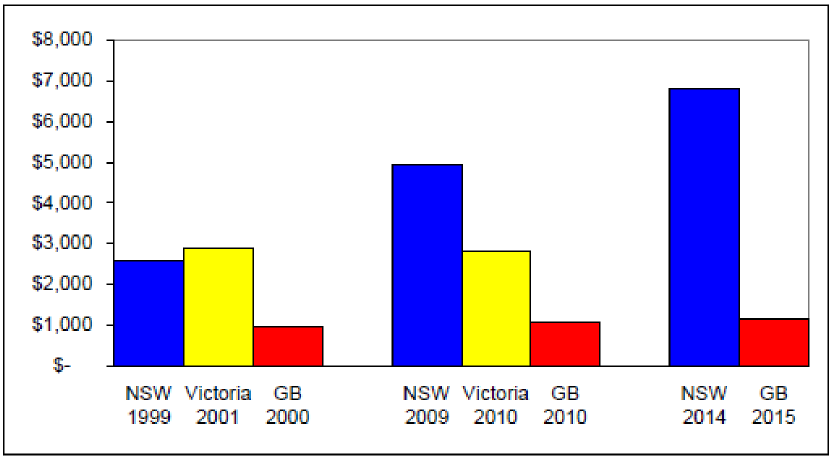


Figure 8 Allowed capex per customer in NSW, Victoria and GB[45] (2008AUD)



Combining new and existing capex, Figure 9 shows that, over the last decade, total net capital employed (RAB) per customer has been higher in Victoria than in GB. But in both cases it has stayed about constant over time whereas it has roughly doubled in NSW.

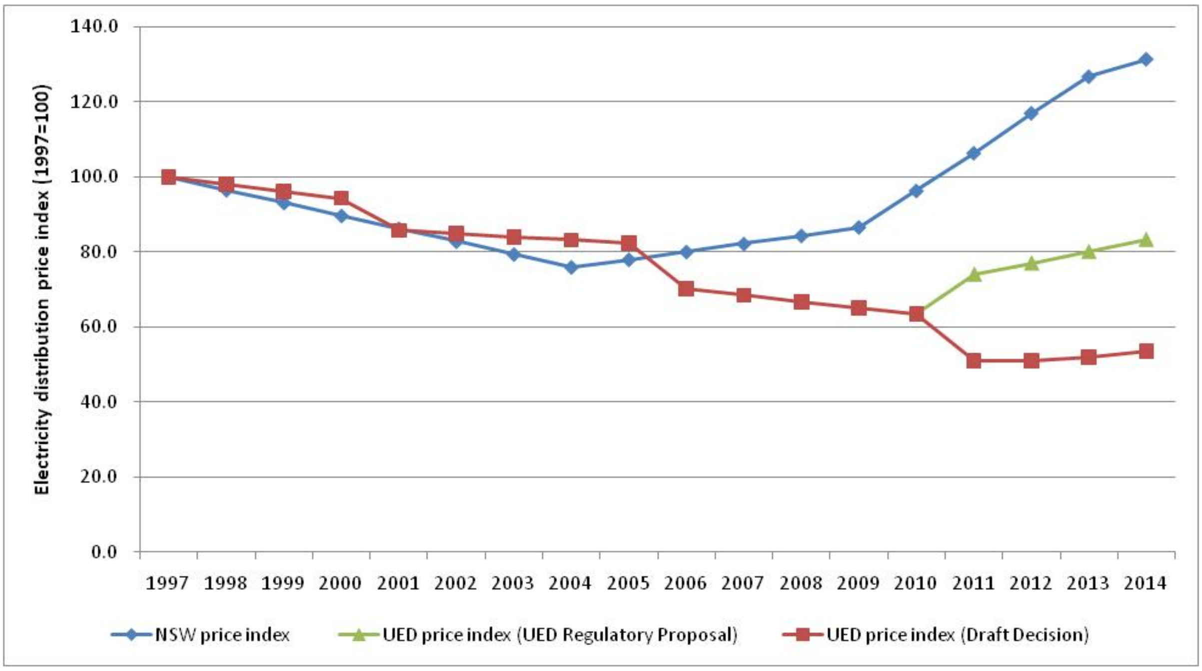
Figure 9. Capital employed (RAB) per customer[46]



It is noteworthy that Mountain and Littlechild employ a number of benchmarking measures, including annual revenue per customer, which is consistent with the measure adopted by UED in its original Regulatory Proposal, as shown in Figure 2.1 above. It is important to recall that Figure 2.1 consistently shows UED to be the lowest cost performer across the 12 distributors in the National Electricity Market. The use of the same benchmark by Mountain and Littlechild makes it especially disappointing that the AER's Draft Decision does not comment on Figure 2.1, and presumably the AER has not considered its relevance in examining the efficiency and prudency of UED's expenditure proposals as required by the Rules.

The independent analysis of Mountain and Littlechild suggests that the gap between NSW and Victoria should not be further widened, yet this is precisely the outcome implied by the AER's Draft Decision. In light of the AER's Draft Decision, UED has updated its earlier price comparison with the NSW distributors (also discussed in UED's original Regulatory Proposal) to show the impact of the AER's Draft Decision should those prices be adopted. The figure below illustrates that the AER's proposed prices in Victoria are significantly out-of-step with the AER's recent decision in NSW and, importantly, the commercial realities facing UED in the forthcoming regulatory period.

Figure 2-4: Comparison of CPI-X price path: UED and New South Wales distributors



The price comparison presented above illustrates that:

- The price increases originally proposed by UED for the forthcoming regulatory period are modest compared to those approved by the AER in its recent determination for NSW distributors;
- If UED's original proposal were to be accepted, UED's distribution prices in 2014 would be 37 per cent lower than those already approved by the AER for New South Wales; and
- If the price controls in the Draft Decision were to be implemented, UED's distribution prices in 2014 would be 60% lower than those approved by the AER in NSW. Under this scenario, distribution prices in NSW would be more than double those of UED by 2014.

Indeed, the very large difference between the expenditure allowances approved by the AER for NSW and those adopted by the AER in the Victorian Draft Decision are inexplicable considering the similarities in the broad circumstances of all Australian DNSPs, in terms of:

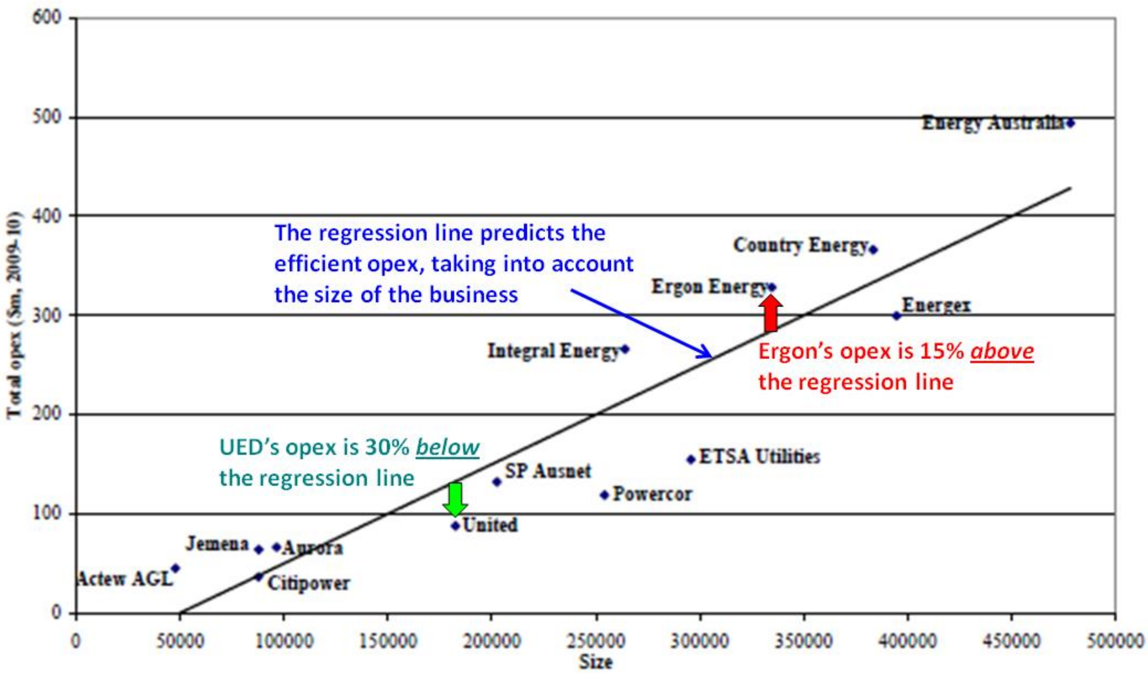
- sustained upward pressures on labour and contracts costs in the context of an on-going resources boom and national markets for labour and materials;
- the need to increase investment and maintenance as the electricity distribution infrastructure installed across Australia in the post-war era ages and approaches the end of its serviceable life;
- the need to meet increasing peak demand and to connect new customers in an economy that has exhibited sustained strong growth over the past decade;
- the need to comply with common health, safety, environmental and technical regulatory obligations; and

- the additional investment and operating expenditure required to address issues relating to climate change.

Similar discrepancies between the AER's treatment of UED and DNSPs in other states are also evident when the AER's May 2010 distribution determination for Ergon Energy is compared with the June 2010 Victorian Draft Decision for Victoria.

The following regression analysis, which we have annotated, appears in Appendix I of the AER's Draft Decision of 25 November 2009 on Queensland DNSPs.

Figure 2-5: AER Opex Benchmarking



The AER's regression analysis essentially benchmarks the Australian DNSPs by comparing each DNSP's actual costs with its predicted cost (indicated by the straight line) based on its size. In comparing UED and Ergon Energy, the benchmarking analysis shows that:

- UED's operating expenditure is approximately 30 per cent lower than the efficient expenditure predicted by the AER's analysis;
- Ergon Energy's operating expenditure is approximately 15 per cent higher that the predicted efficient expenditure.

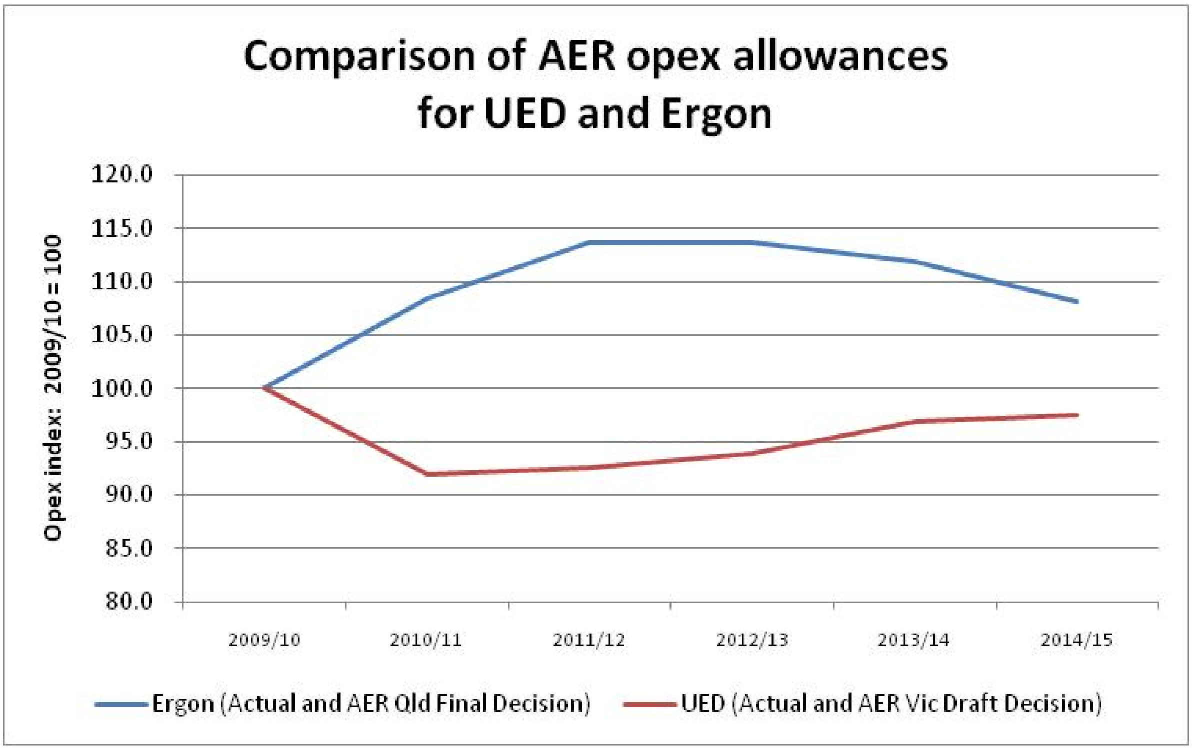
It is also noteworthy that the AER's regression line has a negative intercept on the vertical axis. A properly constructed analysis would be constrained to ensure that the regression line cuts the vertical axis at a value greater than or equal to zero. It is likely that a regression analysis constrained in such a manner would show UED to be an even better performer.

Notwithstanding these observations that can be drawn from the AER's benchmarking analysis:

- The AER's Final Decision for Queensland provided Ergon Energy with a substantial increase in its operating expenditure allowance compared to the company's recent expenditure, which should be regarded as relatively inefficient.
- The Victorian Draft Decision, on the other hand, imposes a significant reduction in UED's operating expenditure allowance, even though UED should be regarded as a superior cost performer, being 30 per cent more efficient than the AER's predicted costs.

This counter-intuitive outcome is illustrated in the figure below.

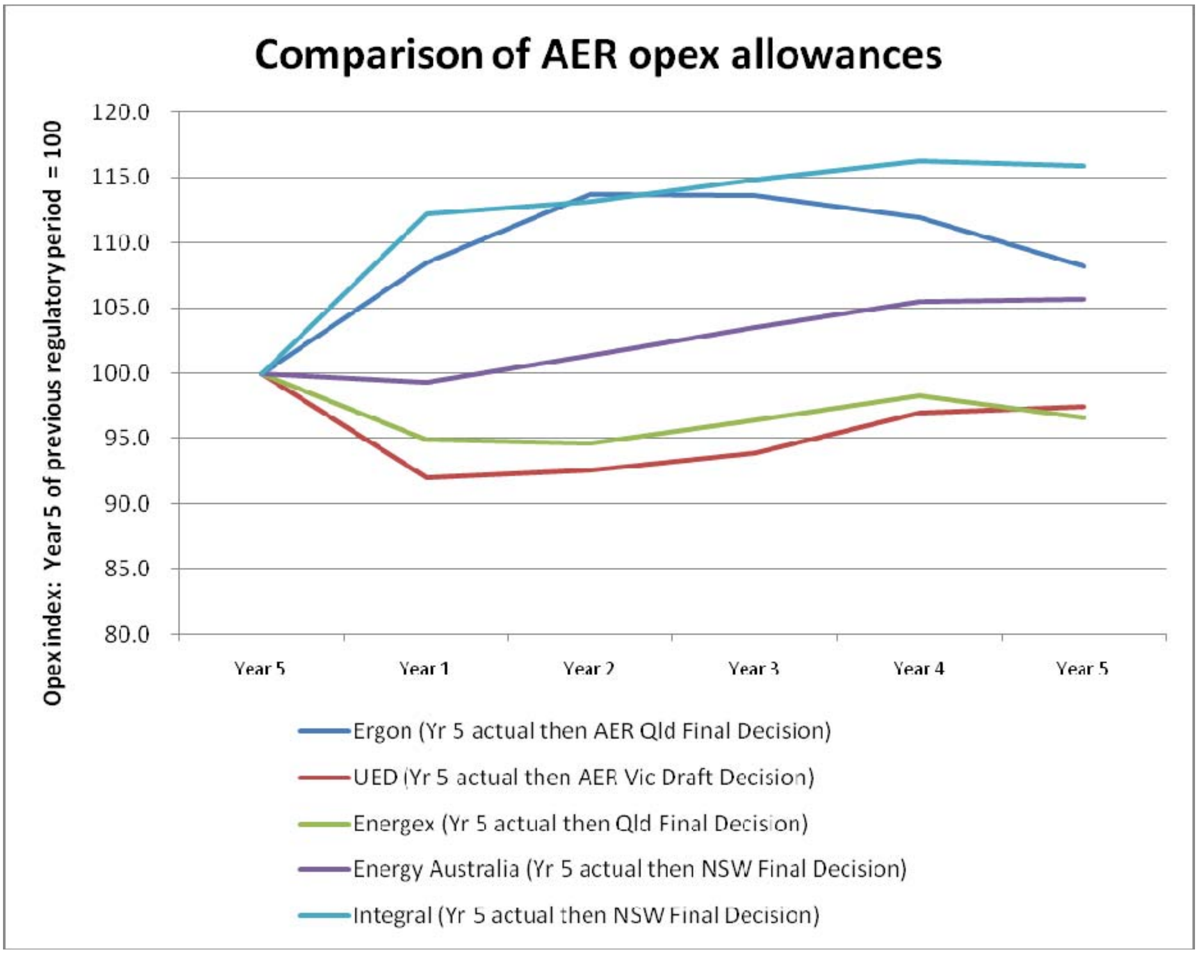
Figure 2-6 Comparison AER opex allowances for UED and Ergon in the June 2010 Victorian Draft Decision and the May 2010 Queensland Final Decision



This analysis illustrates the punitive nature of the AER's Draft Decision for UED compared to its recent determinations for DNSPs in other states. It suggests an element of inconsistency and randomness in the AER's assessment of UED's Regulatory Proposal compared to the approach undertaken in other jurisdictions. As discussed in further detail below, UED contends that this type of inconsistency and randomness does not promote effective incentives or economic efficiency, as required by the Revenue and Pricing Principles in the National Electricity Law.

A comparison of the AER's Draft Decision for UED with recent Final Decisions for a selection of four Queensland and NSW DNSPs shows that UED has been provided with the most unfavourable operating expenditure allowance by the AER, in spite of UED's high level of efficiency compared to the other DNSPs.

Figure 2-7 Comparison of AER opex allowances for UED in the June 2010 Victorian Draft Decision and a sample DNSPs from the April 2009 NSW Final Decision and the Queensland May 2010 Final Decision



As already noted, consistent regulatory decision-making through time is required to ensure the ongoing integrity of the regulatory framework. The analysis set out above demonstrates that the AER has adopted an inconsistent approach in its application of the Rules in the Victorian Draft Decision, compared to the approach it adopted in its recent Queensland and NSW determinations. UED considers that the AER's imposition of very significant reductions in UED's expenditure forecasts is unjustified and unreasonable in light of:

- the results of the AER's own benchmarking analysis, which shows UED to be a superior performer compared to the NSW and Queensland DNSPs; and
- the comparatively high expenditure forecasts accepted by the AER as being efficient in the NSW and Queensland Final Decisions.

In short, there is no reasonable basis for the AER to deem UED's expenditure forecasts inefficient, in light of the expenditure forecasts that the AER has accepted in its NSW and Queensland determinations.

In considering this Revised Regulatory Proposal, UED notes that section 16(2) of the National Electricity Law provides that the AER must take full account of the Revenue and Pricing Principles in the National Electricity Law, which include the following requirements:

> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and
>
> (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

Providing "effective incentives in order to promote economic efficiency" requires the AER to provide financial incentives to encourage and reward low cost distributors, such as UED. Effective incentives cannot be provided if the AER adopts an inconsistent approach to assessing the expenditure proposals submitted by distributors. UED considers that the AER has established clear precedents by adopting the expenditure forecasts that it has in NSW and Queensland. The AER must consider the precedent that it has set in other jurisdictions when it examines the efficiency and prudency of UED's expenditure forecasts.

More broadly, UED is concerned that the approach adopted by the AER in the Victorian Draft Decision, if implemented, will undermine incentives for efficient investment in and operation of networks, contrary to the requirements of the National Electricity Law and the Rules. This is because the AER's reliance on "revealed" costs to set expenditure allowances in future periods rewards and reinforces mediocrity and inefficient performance, whilst penalising – through the provision of reduced expenditure allowances – companies that innovate and deliver efficiency improvements.

In this context, it is also noted that clauses 6.5.6 and 6.5.7 of the Rules require UED to provide forecasts of operating and capital expenditure (respectively). UED considers that the AER's rejection of UED's forecasts, and the adoption of an approach of "projecting" UED's recent actual costs to derive expenditure allowances for the purpose of the Draft Decision fails to meet the requirements of the Rules. Further detailed analysis of the AER's approach to assessing UED's operating and capital expenditure forecasts are presented in Chapters 5 and 6 respectively.

UED has obtained an independent expert opinion from Philip Williams of Frontier Economics, which examines the meaning and application of clause 6.5.6(c) of the Rules. In this independent expert report, Philip Williams comments on the AER's benchmarking analysis in the following terms[8]

> "In my view, the AER's benchmarking analysis in Appendix I of its Draft Decision and noted above does not go far enough to allow the AER to properly assess whether UED's forecast operating expenditure is efficient. The AER itself concedes that the data used in its analysis have not been corrected for differences in regulatory environment, asset classifications, network maturity and geographical factors. In addition, the AER's findings in its draft decision on the Queensland DNSPs also appear too limited to come to firm conclusions, although they do show UED to be significantly more efficient than most DNSPs in the NEM.

[8] Philip Williams, Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery, July 2010, paragraphs 70 and 71.

> Keeping these caveats in mind, I note that on their face, per customer revenues of DNSPs in Victoria appear to be significantly lower than per customer revenues for DNSPs in New South Wales and this seems to be in part the result of lower operating expenditure per customer by Victorian DNSPs. This difference in expenditures may be due to non-efficiency reasons, but the AER's analysis does not show this to be the case. In this context, I find it odd that the AER has rejected UED's operating expenditure forecast as not reflecting efficient and prudent costs."

UED concurs with Philip Williams' view that the available evidence shows UED to be an efficient distributor, and that it is odd that the AER has not accepted UED's forecasts as prudent and efficient. It is evident from the information presented above, that the Draft Decision imposes very significant price reductions on UED over the next five years whilst allowing substantial increases in NSW, even though UED's total cost base today is some 34 per cent lower than the NSW businesses. It is critically important that the AER addresses properly this price benchmarking issue in its Final Decision.

The remainder of this Revised Regulatory Proposal provides further detailed information to substantiate UED's case for a price increase, albeit at a more modest rate than that already approved by the AER in other jurisdictions..

3. UED's business model and business transformation

Key messages

UED's original Regulatory Proposal explained that:

- UED was undertaking a business transformation project to build on the benefits already achieved, establish greater business flexibility to best manage future change and risk, and deliver a better value proposition to our customers.
- The competitive tender process (which has since been completed) confirmed the market's appetite for certain aspects of UED's proposed new business model. This model adopts a 'best of breed' contractor model, in which UED and its customers would obtain the cost and service benefit from the best performers for each service, and so deliver a more efficient model than currently exists.
- The business transformation project would, involve some upfront costs (for instance, in implementing new business processes and systems, and meeting the costs of redundancies associated with gaining efficiencies), so as to deliver greater cost reductions going forward, when compared with a projection of costs under the current business model.
- UED believes that the present service provider (JAM) had a right to match the winning bidder.

The AER's Draft Decision raised concerns regarding UED's business transformation:

- The competitiveness of UED's tender process may have been compromised by JAM's "right to match" and in respect of this right, contractual provisions that require the new service provider to take an equity stake in UED.
- UED's reference line calculation does not provide a reasonable estimate of the costs of the existing business model, and therefore does not demonstrate the efficiency of UED's new business model.

In this Revised Regulatory Proposal, UED explains that:

- As per its original Regulatory Proposal, UED has decided to adopt a new business model based on a broad assessment of benefits that go beyond a simple cost comparison with the existing business model.
- The market testing process was highly competitive, as borne out by the strong commitment of bidders, and has confirmed the market's appetite for UED's new business model.
- The AER has misunderstood or mischaracterised UED's reference line calculation. A properly constructed reference line supports UED's decision to adopt its new business model. This issue is examined in further detail in Chapter 5 of this Revised Regulatory Proposal.
- Under the OSA, UED may, but is not obliged to, put a 'match' offer from a single service provider for all the services for a five year term to JAM. The market testing

exercise has not triggered this right.

- UED does not intend to require any new service provider(s) to take an equity stake in UED.
- The dispute between UED and JAM regarding the right to match provisions in the OSA has now been resolved. The arbitration decision does not affect UED's expenditure forecasts for the 2011-2015 regulatory period

3.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal explained that its current business model is centred on:

- a small management structure that conducts strategic management and corporate governance activities both within the distribution business and through services provided by its parent entity DUET; and
- a single outsourcing agreement (the Operating Services Agreement or "OSA") with Jemena Asset Management (formerly Alinta Asset Management) for all of UED's direct business operations and a number of corporate and back office functions.

UED explained that the current model has enabled the company to build on the significant cost efficiencies achieved in the reform of the Victorian electricity and gas sectors at the time of privatisation. However, while the OSA has provided very strong incentives for JAM to reduce its costs, it has not always provided sufficient layers of control to best manage UED's future operational and performance risks from the owners' perspective. UED is concerned that incentives under the OSA encourage JAM to "over-shoot" – that is, to reduce costs and to increase risks to UED as owner of the distribution network, to unsustainable levels.

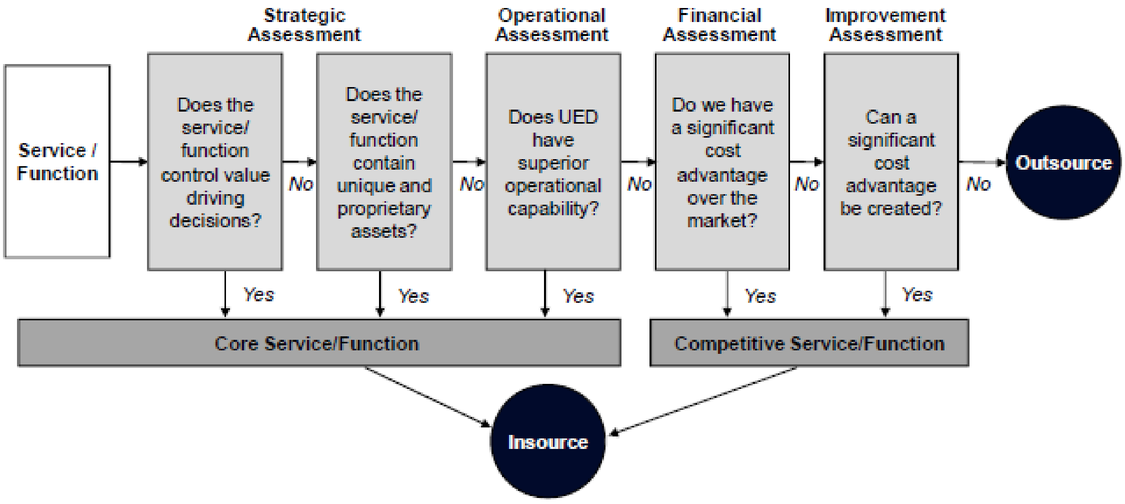
The original Regulatory Proposal explained that UED has therefore concluded that the OSA arrangements should not continue in their present form beyond July 2011. In particular, UED's reliance on a single service provider providing services on a fixed fee basis has created operational, commercial and regulatory risks for UED that are now assessed by UED as being unacceptably high.

UED engaged AT Kearney to assist in the development and implementation of a business transformation project (termed "Project 7/11") aimed at optimising the mix of services to be provided internally and those to be procured through outsourced contracts, and to establish best-practice procurement arrangements for those outsourced services. AT Kearney has invaluable experience in assisting companies with their outsourcing strategies, including the design of optimal contractual terms and conditions.

UED's Board concluded that its preferred business model should engage one or more contractor/ consortia which comprise "best of breed" contractors, selected following a competitive tender process. In this context, best of breed contractors are specialist service providers in a particular field that successfully operate in that field on a national and international basis, bring specialist knowledge skills and economies of scale and scope, are sought by clients (like UED) for outsourcing projects, and have a proven track record of winning tenders and delivering benefits to those clients. By engaging one or more contractor/ consortia which comprise best of breed contractors, UED obtains significant benefits in terms of cost and performance compared to the current OSA arrangement.

Prior to commencing its market testing exercise, UED utilised a "make/buy" decision framework to determine which services should be outsourced and which should be brought back in-house. UED's original Regulatory Proposal explained that the systematic framework applied to the make-buy decision recognises UED's actual circumstances and capabilities. It is not a theoretical or conceptual exercise, but rather it is focused on delivering the right business decisions for UED and its customers, having regard to UED's circumstances. UED's business decisions in this matter are therefore consistent with the letter and spirit of the National Electricity Law and the Rules. An overview of this make/buy decision framework is provided in Figure E5 below.

Figure 3-1 "Make/Buy" decision framework overview



In order to validate UED's make/buy decisions and to help determine the optimal outsourcing model UED, with the assistance of AT Kearney, also looked at recent outsourcing experience both in Australia and globally. AT Kearney also provided advice to UED on the design of the future service contract so that the objectives of the client (UED) and the service provider(s) are strongly aligned, and both parties 'win' or 'lose' together, rather than an environment where one party wins at the other's expense. This achieves a range of efficiencies in the initial pricing - by avoiding either party assuming inappropriate risks - and in service delivery, by minimising the scope for disputes.

UED adopted a highly competitive market testing process which was aimed at testing market's appetite for UED's new business model and to identify potential service providers. The tendering process was designed in accordance with a probity plan, and it has been subject to a probity audit by Dench McClean Carlson. UED adopted strict probity protocols throughout the process to ensure the integrity of the process at all times.

UED sought expressions of interest from suppliers so that it could ascertain the level of interest, and potential capability, in the market. A total of 61 potential suppliers submitted responses to UED's Expression Of Interest, of which a total of 36 respondents were assessed as being "Prequalified Respondents" and capable of providing some of the services being tendered. This level of response – which was subsequently shortlisted to seven – demonstrates the competitive nature of the tender process.

UED compared the tendered costs (including 'restructuring' or 'transformation' costs) with other options, including a projection of the current cost structure, and the preferred business model is expected to deliver much improved outcomes, demonstrating:

- the benefits of the proposed restructuring; and
- the benefits of the best of breed model.

Figure 3-2 and Figure 3-3 below compared two operating expenditure scenarios: a "reference line" (which is a projection of costs under the existing business model), and the expenditure forecasts for UED's proposed new business model (denoted "EDPR forecast"), based on the bid provided by the lowest cost consortium. These charts show that UED's proposed business transformation delivers substantial benefits over a five and 10 year period.

Figure 3-2: UED's five year comparisons (OPEX) – DUOS opex only

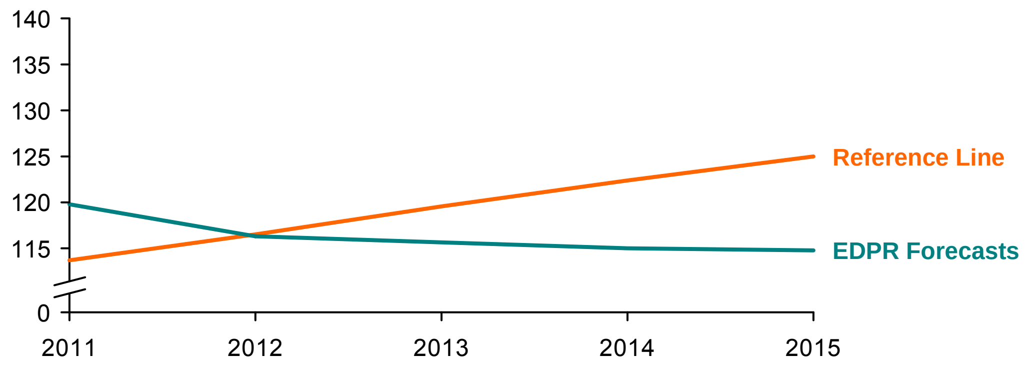
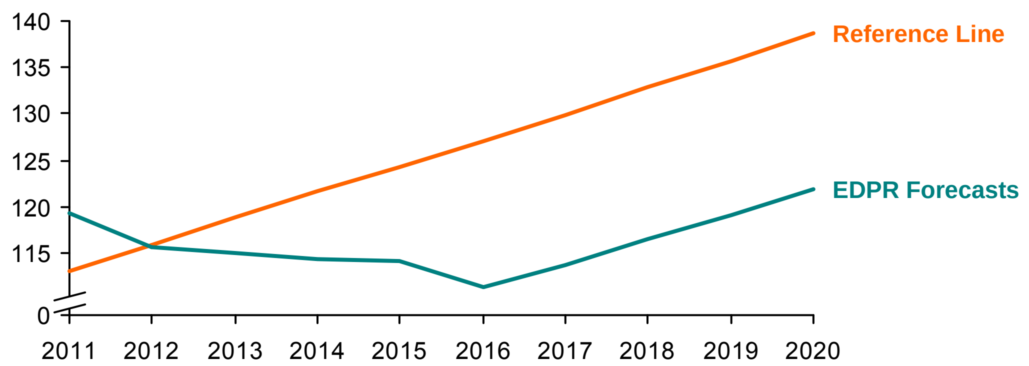


Figure 3-3: UED's 10 year comparisons (OPEX) – DUOS opex only



Note: The reference line in Figure 3-2 and Figure 3-3 is calculated based on the actual cost of services rolled forward using the rate of change calculation adopted in the current benchmarks[9].

9 An appendix is attached that details the assumptions supporting the calculation of the reference point.

UED noted that the above data shows that the transformation to UED's preferred business model will involve some upfront costs (e.g. implementing new systems, payment of redundancies associated with efficiencies, and so on), but this will deliver cost reductions going forward that will more than offset the initial costs. By the end of the five year period UED's cost structure will be lower than for the reference case (i.e. a projection of current costs), with further gains expected over ten years. The NPV analysis effectively demonstrates that the transformation costs have a short payback period.

After UED submitted its original Regulatory Proposal, the AER sought further information from UED regarding the above analysis. As a result of this inquiry, UED revisited the reference line calculations:

- using 2008 costs as a starting point, rather than 2009 costs as shown above; and
- using 2009 costs, updated for JAM's actual losses in 2009, which subsequently became available.

Under both of these scenarios, the new business model was shown to be superior to the reference line, and substantially so in relation to the latter case. This information was provided to the AER on 29 March 2010. Importantly, however, UED also explained that the NPV cost comparison presented in the original Regulatory Proposal is not the sole basis of UED's decision to move to the new business model. As noted above, the new business model will deliver broader performance and governance benefits compared to the status quo. Furthermore, the reference line implicitly assumes that the OSA is renewed on the same or substantially the same terms, and therefore does not take account of the improvements that will be achieved by adopting the new business model. .

UED's original Regulatory Proposal explained that the existing OSA includes a provision under which the existing service provider (JAM) may match the winning bid. UED noted that in the event that JAM did match, they would be matching a contract to restructure the business, in accordance with UED's new business model, and not just operate the network on a status-quo basis. JAM would therefore be held to match the terms of the winning bid, including the transformation program that was aimed at delivering the operational efficiencies identified by the tender process. UED noted that it was then in dispute with JAM in relation to its right to match, but that this dispute is not expected to impact on:

- UED's operating and capital expenditure forecasts presented in UED's original Regulatory Proposal i.e. the market tested pricing will continue to apply whether or not JAM exercises its right to match;
- UED's ability to implement best practice contractual and governance arrangements which provide UED with enhanced flexibility and control; or
- UED's ability to transform its business in the manner described in UED's original Regulatory Proposal, including the implementation of the two region model.

3.2 AER's Draft Decision on UED's business model and business transformation

In relation to UED's competitive tender exercise, the AER commented as follows[10]:

> "The AER has reviewed United Energy's tendering process and considers that the process adopted by United Energy appears reasonably competitive and involved a large number of applicants. That said, the AER has some concerns with the competitiveness of this process in relation to two clauses in the current JAM contract which:
>
> - provide JAM with a 'right to match' the terms of any future contract that replaces its existing contract; and
> - require any contractor that replaces JAM (or some other entity) to offer to purchase at least a certain proportion of United Energy (from Jemena) at a price determined by an independent valuer.
>
> The AER considers that these clauses in the current contract may have dissuaded some applicants from participating in the tendering process or from rigorously competing for it under the knowledge that even if they were the preferred bidder JAM might exercise its right and end up with the contract.
>
> Notwithstanding the potential concerns the AER has over the competitiveness of the tendering process, the fact that four consortia sought to be involved in the final stage of the tendering process indicates that the process was likely to have been reasonably competitive. Accordingly, the AER considers that the new agreement with the preferred tender applicant passes the presumption threshold and the AER can presume that the contract charges under this contract reasonably reflect the efficient costs that would be incurred by a prudent operator in the circumstances of UED."

The AER's Draft Decision raises several issues with the calculation of UED's reference line estimate. In particular, the AER commented that[11]:

- The 'base year' estimate from which the reference line is forecast overstates the costs UED would incur under the continuation of its current business model due to the inclusion of transformational costs currently being incurred by UED in transitioning to its new business model.
- UED applies the 'rate of change' factor adopted by the ESCV in the EDPR for the current 2006–10 regulatory period. The AER considers that it is unlikely this rate of change assumption results in a realistic forecast for the 2011–15 regulatory control period, given it was only intended to be a forecast for the 2006–10 regulatory control period.
- The different cost profiles imply that JAM is expected to face a rising cost profile over the forthcoming regulatory control period whereas the winning tender application is expected to face a much lower cost profile. UED has not presented the AER with information that would demonstrate that it is reasonable to assume that JAM and the winning tender applicant would have differing cost profiles.

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10 AER, Draft Decision, page 198.

11 AER, Draft Decision, page 234.

- UED has qualified the purpose and usefulness of the reference line estimate. The AER is therefore not satisfied that the comparison of the reference line estimate against United Energy's opex forecast demonstrates that United Energy's opex forecast reasonably reflects efficient costs that would be incurred by a prudent operator in United Energy's circumstances, or a realistic expectation of input costs.

3.3 UED's response to the AER's Draft Decision on UED's business model and business transformation

The AER accepts that the contract charges reasonably reflect the efficient costs that would be incurred by a prudent operator in the circumstances of UED[12]. Notwithstanding the AER's acceptance of the contract terms, the Draft Decision commented that the competitiveness of the tender exercise may have been compromised because JAM may exercise its right to match and prevent the winning bidder from providing any services.

In response to the concerns raised by the AER, UED notes that its two region model provided bidders with confidence that the successful tenderer would provide services in at least one of the regions. UED explained this point in its original Regulatory Proposal as follows[13]:

> "A further benefit of the two region model is that bidders to the 7/11 Project could reasonably expect to secure at least one of the regions, with JAM possibly providing services for the remaining region depending on whether or not JAM exercises its right to match under the OSA."

UED also noted in its original Regulatory Proposal that it was uncertain whether JAM would match the winning bid or not, but that if they did, they had to 'back themselves' to match the efficiencies of the winning bidder's price[14]. UED further explained that JAM would need to make significant efficiency improvements and transform its business processes and systems if it is to match the winning bid[15]. For the purposes of this Revised Regulatory Proposal, UED reiterates its earlier view that the tender process was in fact highly competitive. UED's view is further evidenced by the significant interest and commitment from bidders at each stage of the tender process. UED also notes that the above market testing exercise has not triggered JAM's 'right to match' under the OSA.

In relation to the reference line calculation, UED notes the AER's concerns regarding the calculation presented in UED's original Regulatory Proposal. UED addressed a number of queries from the AER regarding the reference line calculation following the submission of UED's Regulatory Proposal. The AER's Draft Decision quotes one part of UED's response to the AER's queries in its Draft Decision as follows[16]:

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12 AER, Draft Decision, page 198.

13 UED, Regulatory Proposal, page 20.

14 UED, Regulatory Proposal, page 17.

15 UED, Regulatory Proposal, page 55.

16 UED response to the AER's queries on operating expenditure, 29 March 2010 (page 2) as quoted in the AER's Draft Decision, page 235.

> "The AER appears to have formed an incorrect view that the reference line is central to UED's operating expenditure forecast and its demonstration that it is prudent and efficient."

The AER's Draft Decision then concluded that[17]:

> "Accordingly, given the issues with the calculation of the reference line estimate identified by the AER and the qualifications on its purpose and usefulness as described by United Energy, the AER is not satisfied that the comparison of the reference line estimate against United Energy's opex forecast demonstrates that United Energy's opex forecast reasonably reflects efficient costs that would be incurred by a prudent operator in United Energy's circumstances, or a realistic expectation of input costs."

UED is concerned that the AER's conclusions regarding UED's reference line calculation are based on the AER's misunderstanding or mischaracterisation of the purpose of the reference line. To ensure that a proper understanding of the purpose and usefulness of the reference line calculation is reflected in the AER's Final Decision, UED repeats its earlier explanation to the AER[18] in full as follows:

> "Before turning to the specific questions raised by the AER, it is helpful to explain the background to the 'reference line' calculation set out in UED's regulatory proposal (and further explained in Appendix B6). The AER appears to have formed an incorrect view that the reference line is central to UED's operating expenditure forecast and its demonstration that it is prudent and efficient. In fact, the Board's decision to adopt the new business model was based on a much broader assessment of its benefits compared to the current arrangement, including:
>
> - increasing the resources of UED internal management to give it a greater strategic and commercial management capability;
> - adopting best practice forms of collaborative contracting, reducing reliance on any one contractor and ensuring high levels of transparency and governance in any and all contracting arrangements;
> - achieving the right balance between delivering operating cost efficiencies and maintaining an appropriate longer term risk profile for asset performance;
> - improving on current commercial performance through improved governance, clearer management of business risks and other shareholder value issues;
> - overcoming historic regulatory concerns with UED's current holistic service outsourcing to a related party;
> - demonstrating efficiency through market-based pricing;
> - adopting pricing and incentive structures in the contractual arrangements that are best practice and fit-for-purpose having regard to the objectives of providing efficient cost and service outcomes for UED and its customers in the short, medium and long term;
> - decreasing the risk of inefficient or sub-optimal service performance by adopting a commercial framework that is free of mechanisms that may provide incentives to service providers to engage in under or over-servicing;

[17] AER, Draft Decision, page 235.

[18] UED response to the AER's queries on operating expenditure, 29 March 2010, pages 2 and 3.

- decreasing financial, regulatory and service performance risks that can arise through a misalignment of asset owner and service provider objectives, by establishing alliance contracts based on jointly agreed objectives and budgets, and a shared focus on how to achieve the best outcomes; and
- allowing the business to adapt to the changes expected to impact electricity distribution businesses worldwide in the coming years with a business structure that has greater strategic management capability and flexibility.

As explained in UED's regulatory proposal, the favourable comparison between UED's forecast operating expenditure for the period 2011-2015 and the hypothetical costs indicated by the reference line reaffirms the Board's decision to adopt the new business model, recommended by consultants AT Kearney. Moreover, the analysis shows that the gains from the new business model are likely to grow during the forthcoming regulatory period and into the next regulatory period, as the initial transformation costs in the early years are offset by savings in subsequent years.

It is also important to note that cost increases incurred by UED in 2009 and 2010 in transitioning towards the new business model have been met by UED's shareholders rather than customers. UED's principal focus in its regulatory proposal is in preparing operating expenditure forecasts for the period 2011-2015 that satisfy the requirements of the Rules. Whilst cost comparisons with the reference line provide a useful 'stress test' for UED's forecasts under the new business model, the reference line calculation does not provide a reasonable basis on which to forecast UED's operating expenditure under the new business model."

In this Revised Regulatory Proposal, UED reiterates the above submission made to the AER on 29 March 2010. In particular, UED notes that the reference line comparison provides a 'stress test' for UED's forecasts, and in this sense it is useful in terms of validating the reasonableness of UED's operating expenditure forecasts for the forthcoming regulatory period. However, UED maintains its view that a reference line methodology as set out in UED's original Regulatory Proposal does not provide a reasonable basis for forecasting UED's operating expenditure for the forthcoming regulatory period for the reasons outlined above.

In this Revised Regulatory Proposal, UED has revisited the 'reference line' calculation presented in its original Regulatory Proposal. In particular, Chapter 5 of this Revised Regulatory Proposal provides an updated reference line calculation to reflect:

- the latest information in relation to 2009 actual and 2010 forecast operating expenditure under the existing business model;
- the AER's Draft Decision in relation to UED's operating expenditure, subject to making a number of important adjustments to correct aspects of the AER's approach and calculations; and
- that differences between the existing terms and conditions in the OSA and those that would pertain if the OSA were renewed to accord more closely with the new business model.

UED notes the AER's criticism in its Draft Decision that UED's reference line calculation adopts the ESC's annual escalation rate of 2.37 per cent which applied to the 2006-2010 regulatory period, rather than the 2011-2015 period. UED maintains its view that the adoption of the ESC's escalation rate was a reasonable assumption for the purposes of calculating the reference line.[19] Nevertheless, in light of the Draft Decision, UED reconsiders the appropriate escalation rate in Chapter 5 of this Revised Regulatory Proposal.

In this Revised Regulatory Proposal, UED reiterates that the UED Board embarked on its new business model following advice from external consultants AT Kearney. UED has previously provided to the AER, on a confidential basis, a copy of a Board paper dated 14 April 2009 (presented at the 24 April 2009 Board meeting), which contains further detailed information regarding the rationale for the adoption of UED's preferred business model. Two further Board papers charting UED's progress in bringing its preferred business model to fruition were also provided to the AER.

These Board papers, along with the other information provided by UED in its original Regulatory Proposal and in response to subsequent queries from the AER clearly demonstrate the prudence of the Board's decision to adopt the new business model. The outcomes from the tender process vindicate that decision and provide practical evidence of its prudence.

The benchmarking information presented by UED in its original Regulatory Proposal (and reiterated in section 2 of this Revised Regulatory Proposal) demonstrates clearly that under its new business model, UED will remain an efficient performer. Importantly, the AER's own benchmarking analysis also confirms that UED is an efficient cost performer, as does the AER's 'year 4' method for estimating operating expenditure, providing that this assessment is undertaken correctly[20].

Taken together, these considerations indicate clearly that the costs that UED is forecasting to incur under its new business model reasonably reflect:

1. the efficient costs of achieving the operating and capital expenditure objectives;
2. the costs that a prudent operator in UED's circumstances would require to achieve the operating and capital expenditure objectives; and
3. a realistic expectation of the cost inputs required to achieve the operating and capital expenditure objectives,

in accordance with the requirements of clauses 6.5.6 and 6.5.7 of the Rules.

The remainder of this Revised Regulatory Proposal (chapters 4, 5 and 6 in particular) provides further detailed information to demonstrate that UED's expenditure forecasts under its new business model satisfy all the requirements of the Rules, and must therefore be accepted by the AER.

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[19] The reasonableness of this assumption is validated by comparison with outcomes in NSW and QLD, where each distributor has increased the rate of cost escalation relative to the previous regulatory period.

[20] As explained in Chapter 5, the AER's 'year 4' approach to estimating UED's future operating expenditure is conceptually similar to the reference line calculation. Therefore, Chapter 5 effectively updates the reference line calculation by examining and making a number of important adjustments to the AER's 'year 4' estimating method for UED's operating expenditure.

Before proceeding to present that information however, section 3.4 below provides an update on the status of UED's dispute with JAM regarding UED's move to its new business model.

3.4 Update on the dispute with JAM regarding UED's new business model

UED and JAM have been involved in a formal dispute resolution process in relation to JAM's 'right to match' under the OSA. Background information on the dispute and a summary of the issues in dispute were set out in the letter dated 5 March 2010 from UED's Chief Executive Officer to Chris Pattas of the AER.

UED and JAM referred the issues in dispute to arbitration for final determination. An arbitration hearing was conducted in April 2010 before the Honourable Murray Gleeson AC, the former Chief Justice of the High Court of Australia.

On 29 June 2010, Mr Gleeson handed down his decision on the issues in dispute.

Although the outcome of the arbitration is confidential, UED is now confident that it is not obliged to put an offer to JAM to match under the OSA and that it is able to pursue its long term commercial objectives. UED is currently negotiating with JAM to see whether an agreement can be reached to transform its business including:

- the in-sourcing of certain strategic and management functions currently performed by JAM under the OSA;
- the appointing of "best of breed" subcontractors, particularly in specialist areas such as delivery of information technology services; and
- the adoption of a market best practice incentive-based contracting structure to ensure that the objectives of UED and the service providers are strongly aligned.

Consistent with UED's expectations previously communicated to the AER in conference, in UED's original Regulatory Proposal at section 5.4.3 and in UED's letter dated 5 March 2010, the outcome of the arbitration does not affect UED's expenditure forecasts for the 2011-2015 regulatory period. Under all scenarios, UED, and not its end-customers, bear the risk that UED might incur higher operating costs than forecasted, although this is not expected to be the case.

4. Planning for future demand and service performance

Key messages

UED's original Regulatory Proposal explained that:

- UED's asset management plan comprises a series of 27 individual supporting plans, each focused on particular asset types and attendant risk management issues. UED's work programs aim to maintain the reliability, safety and security of the distribution system.
- UED is investing in increased capacity to meet forecast demand while achieving a high level of asset utilisation. Sophisticated probabilistic planning techniques are utilised to cater for a 10 per cent POE summer day in a typical summer (50 per cent POE) based on summer day average temperature as defined by NIEIR.
- The new Electricity Safety Act will require electricity distribution businesses to develop and maintain an Electricity Safety Management Scheme (ESMS) or "Safety Case". This is a dictates a significant change in approach to meeting regulatory obligations relating to safety management (from plain compliance to an informed risk-based approach), and additional costs will be incurred by UED as a result.
- AECOM and CSIRO's Marine and Atmospheric Research ("CMAR") team have provided an opinion on the likely impact of climate change on UED and its customers, which UED has factored into its expenditure plans. However, targeting service performance against the backdrop of more volatile weather extremes is subject to uncertainty and risk.
- In the medium term, UED's business transformation to a performance-based service delivery model when coupled to UED's proposed asset replacement program should assist UED in reversing the recent trend decline in network reliability.

The AER's Draft Decision found that:

- The capital governance and practices of the DNSPs were well-evolved, fit-for-purpose capital governance processes and practices.
- However, the full extent of these processes has not been applied to these plans. That is, the level of evaluation and justification that may be expected prior to the approval of specific proposed projects and programs have not been applied to the DNSPs' forecasts.

In this Revised Regulatory Proposal, UED's explains that:

- UED welcomes the AER's recognition of the robustness of UED's asset management planning and capital governance processes.
- UED disagrees with Nutall Consulting's conclusion that the full extent of UED's capital governance processes has not been applied to the expenditure forecasts.

4.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal explained that its 2009-2016 asset management plan was thoroughly revised to ensure that it:

- satisfies the standard set by the British Standard Institute (PAS 55), which includes consideration of age-related asset condition;
- captures the latest developments in asset management;
- takes account of emerging technologies; and
- achieves 100 per cent compliance with the company's regulatory obligations.

UED's asset management plan comprises a series of 27 individual supporting plans, each focused on particular asset types and attendant risk management issues. UED's work programs aim to maintain the reliability, safety and security of the distribution system. UED commissioned AECOM to undertake an independent review of the asset management plan, and AECOM endorsed UED's AMP.

UED's original Regulatory Proposal explained that it has adopted a probabilistic approach to planning which tolerates a small risk of loss of supply in circumstances involving outage of plant items at infrequent times of very high network loading. A probabilistic approach provides an economic outcome that minimises the total expected costs faced by customers, by balancing the expected cost of loss of supply against the cost of the additional investment required to remove or reduce the risk of loss of supply. This probabilistic approach to network planning also provides a tool that facilities efficient allocation of expenditure across the network. Implicit in the use of this approach, however, is the acceptance of a certain degree of risk, which UED seeks to manage through contingency planning.

UED proposed a package of measures (both capital and operating) over the forthcoming period that will deliver service performance standards to service performance consistent with historical outcomes by focusing on the worst performing assets and mitigating against a forecast decline in reliability due to increasing asset age and climate change effects, and by aiming to reduce interruptions to supply. UED's original Regulatory Proposal explained that these programs will maintain the reliability, safety and security of the distribution system.

UED's original Regulatory Proposal also highlighted that the company is required to comply with the provisions of the Electricity Safety Act and subordinate regulations and standards relating to the design, construction, operation and maintenance of a distribution network. The new Act and regulations will represent a "paradigm shift" away from highly prescriptive regulation - where electricity companies were required to comply with highly detailed regulatory requirements - to a regime where the risk burden for safe management of the network resides even more so with electricity company. UED identified the additional costs will arise as a result of this paradigm shift.

UED also noted that climate change is already impacting directly on the performance of UED's distribution network. UED is undertaking further work to develop a more storm-resilient electricity network, with the aim of managing the impact of storms on the reliability of electricity supply.[21] Accordingly UED sought independent specialist expertise to provide comprehensive analysis and opinion on the implications of climate change for UED's distribution network and business, having regard to the requirements of the Rules.

AECOM was selected by UED as a suitably-qualified expert to provide this independent opinion and assessment. To ensure a scientifically robust and credible assessment of these impacts, AECOM engaged the expert advice and review of the CSIRO's CMAR team. The CMAR team ensured the appropriate application of climate modelling. Members of the CMAR team include some of Australia's leading climate scientists and, as authors of the Australian component of the IPCC Fourth Assessment Report, are joint Nobel Prize winners.

Based on climate change modelling and correlation of historical network performance with climate conditions, AECOM concluded that the potential effect of wind on UED's network performance and operating costs is significant, with:

- likely increases in costs associated with future storm management and productivity loss estimated to be as high as $1.2 million p.a.; and
- increases in network SAIDI as high as 28 minutes (noting that UED forecast 20 of the 28 minutes to be excluded events for the purposes of the STPIS) over the regulatory period under the HADGEM1 climate model.

The recommendations of AECOM were taken into account in the preparation of UED's original Regulatory Proposal, particularly in relation to capital expenditure forecasts (Chapter 6) and service performance targets (Chapter 16).

4.2 AER's Draft Decision on UED's asset management planning

The AER engaged Nutall Consulting to provide an independent review of UED's capital expenditure forecasts. The scope of the review undertaken by Nutall Consulting included a desktop review of the capital governance practices of UED, as defined in its documented policies and practices provided in support of its original Regulatory Proposal. Nutall's review was carried out in conjunction with the broader review of the capital expenditure proposals submitted by UED for the next regulatory control period.

The Nutall Consulting report[22] contained a number of very positive findings and conclusions regarding the quality of UED's asset management planning. Page 41 of the report states:

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[21] UED notes that the impact of climate change on the water sector has been accepted by jurisdictional regulators, particularly as a consequence of sustained reduction in stream flows that have been observed since the early 1970s. UED acknowledges that climate change impacts in the electricity distribution sector are less obvious, but it is UED's view that it would be unreasonable and commercially unrealistic to ignore the risks posed by climate change impacts. UED also notes that consideration of climate risks in business planning has been specifically endorsed by the Australian Government through publication of *Climate Change Impacts & Risk Management - A Guide for Business and Government*, Australian Greenhouse Office, in the Department of the Environment and Heritage, 2006. The Guide is consistent with the Australian and New Zealand Standard for Risk Management, AS/NZS 4360:2004, which is widely used in the public and private sectors to guide strategic, operational and other forms of risk management.

[22] Nutall Consulting, Report – Capital Expenditure, Victorian Electricity Distribution Revenue Review, Final Report to the AER, 4 June 2010.

"PAS 55:200811 (PAS 55) is a Publicly Available Specification that was developed in response to demand from industry for a standard relating to asset management in infrastructure intensive industries. The approach we have taken to assess DNSP governance documentation against the capex governance requirements is to frame an appropriate subset of criteria derived from PAS 55 and then to assess the documentation against this set of criteria.

Nuttall Consulting considers that the documentation provided by each of the five Victorian DNSPs incorporate well-evolved, fit-for-purpose capital governance processes and practices. They are based on asset management frameworks that have been developed with varying degrees of reference to the PAS 55:2008 standard."

The Nutall Consulting report then proceeds to assess each DNSP's asset management documentation against six criteria derived from PAS 55. The ratings accorded to UED against each criterion are as follows:

Table 4-1: PAS 55 criterion adopted by Nuttall

Description	Rating of UED against this criterion
1. Policy and strategy	High
2. Asset management information	Partial
3. Risk management	High
4. Capital expenditure planning	High
5. Implementation and operation	High
6. Management review and continual improvement	High

Page 42 of the Nutall Consulting report notes that:

Where "partial" ratings have been assessed, we feel that any shortfall may simply be a matter of documentation rigour within the submitted material, as opposed to any material gap in the DNSP's processes or practices. Although, it is worth noting that we have not conducted an investigation to confirm this view.

The Nutall Consulting report then proceeds to state:

"It is important to note that while this review has not attempted to audit the application of these processes, the findings of this review support our position that the DNSPs historical expenditure can be considered reasonably reflective of prudent and efficient levels.

It is also important to stress however that it is clear from our review of the DNSPs plans, discussed further in the section below, that the full extent of these process have not been applied to these plans. This particularly concerns the level of evaluation and justification that may be expected prior to the approval of specific proposed projects and programs."

4.3 UED's response to the AER's Draft Decision on UED's planning for future demand and service performance

UED welcomes the findings of the Nutall Consulting review, which confirm the robustness of UED's asset management planning.

However, UED disagrees with Nutall Consulting's conclusion that the full extent of UED's capital governance processes has not been applied to the expenditure forecasts. UED also rejects Nutall Consulting's reliance on the use of historical expenditure to inform regulatory decisions about future capital expenditure requirements. As noted in detail in Chapter 6, such an approach to determining regulatory allowances for capital expenditure is not consistent with the requirements of clause 6.5.7 of the Rules.

Further detailed information in relation to these matters is set out in Chapter 6 of this Revised Regulatory Proposal.

5. Forecast Operating Expenditure

Key messages

UED's original Regulatory Proposal explained that:

- UED's operating expenditure forecasts reflect the new business model.
- UED undertook a rigorous, competitive tender process to replace the existing OSA, the current term of which expires in July 2011.
- UED's operating expenditure forecasts for its new business model were substantiated by numerous independent expert reports and independent evidence.

The AER's draft determination argued that:

- UED's Regulatory Proposal has not substantiated outsourced work volumes; in-house unit costs and in-house work volumes. The AER found that UED's reference line did not demonstrate the efficiency or prudency of UED's operating expenditure forecasts
- The AER relied on the 'revealed cost' or 'year 4' approach to develop an alternative assessment of UED's operating expenditure for the forthcoming regulatory period.
- The AER removed fees paid to DUET and AMPCI to derive UED's 'base year' costs. The AER also removed costs it assessed to be non-recurrent from the base year.
- The AER's revised operating expenditure forecast for UED imposes a 23 per cent reduction compared to UED's forecasts.

In this Revised Regulatory Proposal, UED explains that:

- UED's new business model necessitates a 'bottom up' forecasting approach, rather than a 'year 4' approach as adopted by the AER's Draft Decision. A year 4 approach does not represent a valid forecast, and as such UED would be breaching the Rules if it developed a forecast of its operating expenditure in that way.
- UED considers that its original Regulatory Proposal fully substantiated its operating expenditure and satisfied the Rules requirements. Nevertheless, this submission provides further information to demonstrate that UED's original operating expenditure forecasts comply with the Rules.
- UED recognises that the AER's 'year 4' approach can be used to 'stress test' UED's forecasts for its new business model, similar to UED's 'reference line' approach. However, the AER's application of its 'year 4' approach for UED contains a number of inappropriate adjustments and escalation factors.
- UED provides a detailed explanation of the amendments that should be made to the AER's 'year 4' approach in order for it to provide a reasonable 'stress test' for UED's operating expenditure forecasts. The amended calculation illustrates that UED's original operating expenditure forecasts for its new business model are reasonable and should be accepted by the AER.
- In the case of the NSW distributors accepted forecasts of operating expenditure that are very substantially higher (on a per unit measure) than the forecasts proposed by UED. However, in the case of the Victorian Draft Decision, the AER rejected UED's

operating expenditure forecasts and imposed significant reductions in UED's operating expenditure allowance. UED considers that the AER has established clear precedents by adopting the operating expenditure forecasts that it has in its recent NSW and Queensland determinations. The AER must consider the precedent that it has set in other jurisdictions when it examines the efficiency and prudency of UED's expenditure forecasts.

- UED has fully substantiated its operating expenditure forecast in accordance with the requirements of the Rules, and in accordance with those requirements the AER must accept UED's forecast operating expenditure for the forthcoming regulatory period.

5.1 Introduction

5.1.1 UED's original Regulatory Proposal

UED's original Regulatory Proposal explained the rationale for UED's new business model, a summary of which is provided in Chapter 3 of this document. To recap, the key changes in the new business model are:

- The establishment of two operating regions within UED's network. Each region will be served by an outsourced service provider selected through a competitive tender.
- The existing operating services agreement with JAM will not be renewed. The new business model will employ best practice contractual arrangements to facilitate better outcomes in terms of cost efficiency; service delivery; governance, cost reporting; and risk management.
- More services will be provided in-house. Bringing services in-house will provide a better balance between obtaining cost efficiencies through outsourcing and the prudency of controlling and managing core business functions in-house. It also ensures that UED management is directly and intimately informed on, and responsible for, all decisions that require consideration of "trade-offs" between service standards and opex or capex costs; and"trade-offs" between opex and capex costs.
- Better control regarding optimisation decisions. UED management will be able to make well-informed decisions regarding trade off opportunities between operating and capital expenditure, and balancing cost efficiencies against service improvements.

UED obtained advice from consultants AT Kearney regarding the design of UED's new business model. Along with its original Regulatory Proposal, UED provided the AER with confidential information, including Board Papers, to demonstrate the prudency of UED's decision to implement its new business model.

UED's original Regulatory Proposal highlighted that the Rules require UED to submit forecasts of annual operating expenditure for the forthcoming regulatory period, and that these forecasts are certified by UED's Directors. Consequently, UED could not employ a 'year 4' roll forward method to forecast operating expenditure, which was the ESCV's standard forecasting approach, because this method implicitly assumes 'business-as-usual' operating conditions. As explained above, UED's business model will change significantly in the forthcoming regulatory period, and therefore its operating expenditure forecast must reflect these changes.

UED's original Regulatory Proposal provided a number of expert reports and independent evidence to support its operating expenditure forecasts as noted in the table below. .

Table 5-1: Expert reports and independent evidence to substantiate UED's original Regulatory Proposal

Matter addressed	Expert/Evidence	Reference
1. Advice on the optimal design of UED's business model	AT Kearney	Regulatory Proposal, Appendix F4
2. Probity plan for the competitive tender process for outsourced services, and subsequent audit	Dench McClean Carlson	Regulatory Proposal, Appendix F6
3. Opinion that UED's expenditure forecasting methodology has been designed and implemented to provide forecasts that comply with the Rules	KPMG	Regulatory Proposal, Appendix C1
4. Opinion that UED's asset management plan adopts work volumes that are consistent with 2009 volumes	AECOM	Regulatory Proposal, Appendix D5
5. Information to demonstrate that salary benchmarks for internal labour are reasonable	Hays 2009 Salary Guide; Hudson 2009 Salary Guide; Michael Page 2009 Salary Guide; and Geoffrey Nunn & Associates Labour Cost Benchmarks.	Provided to AER on confidential basis, 9 March 2010
6. Escalators for internal labour costs based on forecast wages for Victorian distribution businesses	BIS Shrapnel	Regulatory Proposal, Appendix D1
7. Information to demonstrate that internal labour is consistent with European utility benchmarks	AT Kearney	Provided to AER on confidential basis, 9 March 2010
8. Opinion that UED's corporate costs for the new business model are efficient when compared against industry benchmarks	KPMG	Regulatory Proposal, Appendix C1, appendices K and L

5.1.2 AER's Draft Decision

In its Draft Decision, the AER did not accept UED's operating expenditure forecasting methodology or the resulting forecasts. In contrast to UED's position, the AER concluded that it favours a 'year 4' roll forward method to forecast operating expenditure[23]:

[23] AER, Draft Decision, pages 224 and 226.

> "Trend analysis, together with benchmarking the Victorian DNSPs against DNSPs in other jurisdictions, demonstrates that the Victorian DNSPs compare favourably to those in other states. This suggests that the revealed costs of the Victorian DNSPs are a sound base for determining the starting point for evaluating their forecast opex proposals…
>
> The AER considers that the Victorian DNSPs are subject to commercial incentives, both through their governance arrangements and the specific incentive mechanisms of the regulatory framework.
>
> Given that the DNSPs have a continuous incentive to seek cost efficiencies, the AER has relied on the 'revealed cost' approach to inform its assessment of the DNSPs' opex forecasts under clause 6.5.6(c) of the NER. In particular, the AER has placed weight on clause 6.5.6(c)(5) of the NER. The AER has also had regard to some benchmarking analysis in accordance with clause 6.5.6(c)(9) of the NER which supports the AER's reliance on the revealed cost approach (refer to appendix I)."

Table 5-2 of the Draft Decision (reproduced below) explains that UED's forecasts can be split into four components, and summarises the AER's assessment of each component.

Table 5-2: AER Draft Decision – Assessment of different components of United Energy's opex forecast

Component of Forecast	AER Assessment
Outsourced Services – Unit Costs	Unit costs derived from reasonable competitive tender process.
Outsourced Services – Unit Volumes	Unit volumes estimated by United Energy. Not sufficiently substantiated
In-house Services – Unit Costs	Unit costs estimated by United Energy. Source material provided at request of AER subsequent to lodgement of regulatory proposal Connection between source material and forecast not clearly established.
In-house Services – Unit Volumes	Unit volumes estimated by United Energy. Source material provided at request of AER subsequent to lodgement of regulatory proposal. Connection between source material and forecast not clearly established.

Source: AER analysis

As discussed in Chapter 3 of this Revised Regulatory Proposal, the Draft Decision also criticised UED's "reference line" cost comparison, and concluded that it did not demonstrate the efficiency or prudency of UED's operating expenditure forecast[24]:

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[24] AER, Draft Decision, page 235.

"The AER notes that United Energy itself does not purport that the reference line estimate demonstrates its opex forecast meets the requirements of the NER. In response to some questions from the AER on the reference line estimate, United Energy stated:

'The AER appears to have formed an incorrect view that the reference line is central to UED's operating expenditure forecast and its demonstration that it is prudent and efficient.'

Accordingly, given the issues with the calculation of the reference line estimate identified by the AER and the qualifications on its purpose and usefulness as described by United Energy, the AER is not satisfied that the comparison of the reference line estimate against United Energy's opex forecast demonstrates that United Energy's opex forecast reasonably reflects efficient costs that would be incurred by a prudent operator in United Energy's circumstances, or a realistic expectation of input costs."

The AER concluded its assessment of UED's operating expenditure forecast in the following terms[25]:

"The AER considers that United Energy conducted a reasonably competitive tender process and so the unit costs for outsourced services arising from this tender reasonably reflect efficient costs. However, these unit costs are only one of four components of United Energy's opex forecast. The AER considers that the reasonableness of the other three components (in-house unit costs, in-house unit volumes, out-sourced unit volumes) has not been substantiated in United Energy's proposal or in the additional information provided by United Energy in response to the AER's information requests.

In particular, due to the issues identified above in relation to the 'reference point' estimate, and the qualifications placed on this estimate by United Energy, this topdown analysis does not demonstrate the efficiency or prudence of United Energy's new business model (or at least, United Energy's opex forecasts under its new business model).

As United Energy's forecast opex is derived from these four components, the AER is not satisfied that United Energy's opex forecast reasonably reflects the opex criteria.

The AER's estimate of the required opex, which is the minimum adjustment it considers necessary to be in accordance with the requirements of the NER, is derived from:

- a 'base year' opex derived mostly from the historical actual expenditure of operating United Energy's network under its current business model
- adjusted for scale, real cost escalators and step changes in the same manner as for the other Victorian DNSPs."

The AER's revised operating expenditure forecasts for UED are summarised in Table 7.34 and Figure 7.9 of the Draft Decision, which are reproduced below.

Table 5-3: United Energy draft decision opex allowance ($'m 2010)

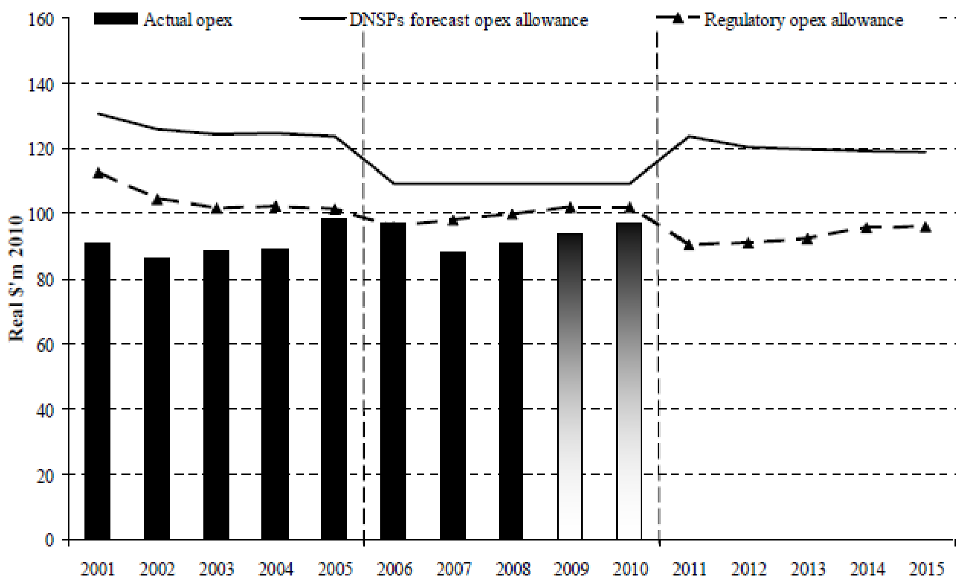
	2011	2012	2013	2014	2015	Total (2011-15)
United Energy proposed opex	**123.8**	**120.2**	**119.7**	**119.2**	**118.9**	**601.8**
AER opex build-up						

[25] AER, Draft Decision, page 235.

AER base year costs	85.0	85.0	85.0	85.0	85.0	424.8
AER scale escalation	0.3	0.6	0.9	1.2	1.5	4.6
AER real cost escalation	1.6	2.4	3.4	4.7	5.5	17.6
AER step changes	2.2	1.6	1.6	3.0	2.4	10.9
AE debt raising costs	0.8	0.8	0.8	0.8	0.8	4.0
AER self insurance	0.0	0.0	0.0	0.0	0.0	0.1
AER other[(a)]	0.7	0.7	0.7	0.7	0.7	3.3
AER total opex	**90.5**	**91.1**	**92.4**	**95.4**	**95.9**	**465.3**
Adjustment	**-33.3**	**-29.1**	**-27.3**	**-23.8**	**-23.0**	**-136.5**
Adjustment)per cent)	**-26.9**	**-24.2**	**-22.8**	**-19.9**	**-19.3**	**-22.7**

(a) SMIS, GSL

Figure 7.9 United Energy draft decision opex allowance



5.1.3 Overview of UED's response to the Draft Decision

UED is extremely concerned about the extent of the very significant reductions to UED's forecast operating expenditure imposed by the Draft Decision. The AER's proposed operating expenditure allowance is insufficient to enable UED to satisfy the operating expenditure objectives (specified in clause 6.5.6(a) of the Rules), which require that UED must be able to:

(1) meet or manage the expected demand for standard control services;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) maintain the quality, reliability and security of supply of standard control services;

(4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

As explained in section 5.1.1 above, UED provided substantial evidence to the AER in support of its operating expenditure forecasts, including independent reports from suitably qualified experts. UED stands by its original operating expenditure forecasts, which the company considers to be consistent with clause 6.5.6(c) of the Rules, which requires:

> " … the total of the forecast operating expenditure for the regulatory control period reasonably reflects:
>
> (i) the efficient costs of achieving the operating expenditure objectives; and
>
> (ii) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and
>
> (iii) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives."
>
> (the operating expenditure criteria)."

It is noteworthy that clause 6.5.6(c) of the Rules requires the AER to accept UED's operating expenditure forecast if the AER is satisfied that the total of the forecast operating expenditure reasonably reflects the criteria set out in that clause. UED considers that the Draft Decision fails to demonstrate that UED's operating expenditure forecast does not meet the operating expenditure criteria. In this regard, it is particularly instructive to examine the operating expenditure forecasts that have been accepted by the AER in its recent determinations for NSW, Queensland and South Australia.

As noted in Chapter 2 of this Revised Regulatory Proposal, the AER has, in the case of the NSW distributors accepted forecasts of operating expenditure that are very substantially *higher* (on a per unit measure) than the forecasts proposed by UED. However, in the case of the Victorian Draft Decision, the AER rejected UED's operating expenditure forecasts and imposed significant *reductions* in UED's operating expenditure allowance. As noted in Chapter 2, the difference between the expenditure forecasts accepted under the Rules by the AER in NSW and Queensland, and the operating expenditure allowance determined for UED in the Draft Decision are simply inexplicable, especially considering the similarities in the broad circumstances of all Australian DNSPs, in terms of:

- sustained upward pressures on labour and contracts costs in the context of an on-going resources boom and national markets for labour and materials;

- the need to increase investment and maintenance as electricity distribution infrastructure installed in the post-war era ages and approaches the end of its serviceable life;

- the need to meet increasing peak demand and to connect new customers in a economy that has exhibited sustained strong growth over the past decade; and

- the additional investment and operating expenditure required to address issues relating to climate change.

UED considers that the AER has established clear precedents by adopting the operating expenditure forecasts that it has in its recent NSW and Queensland determinations. The AER must consider the precedent that it has set in other jurisdictions when it examines the efficiency and prudency of UED's expenditure forecasts.

As also noted in Chapter 2, UED has obtained an independent expert opinion from Philip Williams of Frontier Economics regarding the interpretation and application of clause 6.5.6(c) of the Rules. In light of the available benchmarking information, Philip Williams comments that he finds it odd that the AER has rejected UED's operating expenditure forecast as not reflecting efficient and prudent costs.[26] UED concurs with Philip Williams' view. In short, UED considers that:

- the AER has not properly assessed UED's operating expenditure forecast in accordance with the requirements of the Rules;

- the Draft Decision fails to substantiate the AER's conclusion that UED's operating expenditure forecast does not meet the requirements of clause 6.5.6(c); and

- the AER's assessment and amendment of UED's operating expenditure forecast does not accord with the requirements of clause 6.12.3 of the Rules.

Against this backdrop, the purpose of this Revised Regulatory Proposal is to respond in detail to the issues raised by the AER in its Draft Decision. As explained in section 5.1.2 above, the AER's Draft Decision criticises UED's forecasting methodology and the expenditure forecasts it produces, and then develops its own alternative estimate of UED's operating expenditure requirements. In estimating UED's operating expenditure the AER is bound to observe the form of the regulatory proposal submitted by UED when reviewing or correcting the building block methodology. It has not done this. Accordingly given the importance of these matters, UED's response in relation to operating expenditure is structured as follows:

- Section 5.2 below addresses the AER's criticisms of UED's methodology and forecasts. UED provides further information to address the AER's concerns regarding three of the four forecasting elements.

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[26] Philip Williams, Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery, July 2010, paragraph 71.

- Section 5.3 responds to the AER's proposed alternative operating expenditure forecast for UED, which is based on a 'year 4' roll forward approach. UED notes that the AER's approach is conceptually similar to UED's 'reference line', and therefore that approach can provide a high-level cross-check that UED's operating expenditure forecasts are reasonable. However, various adjustments and corrections need to be made to the AER's assessment contained in the Draft Decision in order to provide a valid and meaningful cross-check. This section provides a detailed explanation and justification for these various adjustments.
- Section 5.4 presents UED's concluding comments and updated operating expenditure forecasts.

It should be noted that some cost items – such as step changes – are relevant to both sections 5.2 and 5.3. To avoid unnecessary duplication, however, these matters are addressed in section 5.3 only.

5.2 Response to the AER's criticisms of UED's forecasts

5.2.1 Introduction

As noted in section 5.1.2 above, the AER's Draft Decision concluded that UED provided insufficient substantiation of the following three forecasting elements:

- The volume of outsourced services;
- The unit costs for in-house services; and
- The unit volumes for in-house services.

The following sections address the AER's concerns for each of the three forecasting elements by:

- recapping on the key expert reports and independent evidence provided in UED's original Regulatory Proposal to substantiate the reasonableness of UED's forecast; and
- where appropriate, providing additional supporting information to further substantiate UED's forecast.

UED also explains that in relation to in-house costs, it is important to distinguish between labour and non-labour costs. The former can be addressed in terms of "unit costs" and "volumes" as per the AER's Draft Decision. However, non-labour costs are more appropriately reviewed on a total cost basis, as explained in section 5.2.4 below.

Before turning to a more detailed examination and substantiation of the three forecasting elements listed above, section 5.2.2 provides a summary of a further expert opinion from KPMG which responds to the AER's concerns that UED's operating expenditure forecasts were not sufficiently substantiated.

5.2.2 KPMG's further expert report on UED's operating expenditure forecasts

As already noted, KPMG reviewed and endorsed the expenditure forecasting methodology employed by UED in the development of its original Regulatory Proposal[27]. KPMG provided independent assurance that UED's operating expenditure forecasting methodology complies with the requirements of the Rules that relate to the preparation of expenditure forecasts, and is likely to produce forecasts that reasonably reflect the efficient costs of achieving the operating expenditure objectives set out in the Rules; and the costs that a prudent operator in UED's circumstances would require to achieve the operating expenditure objectives.

Given the level of detail of KPMG's review of UED's expenditure forecasting methodology, UED was somewhat surprised that that the AER had found the forecasts to be inadequately substantiated.

Following the publication of the Draft Decision, UED commissioned KPMG to prepare a further report[28] to recap on the evidence and conclusions set out in the first (November 2009) KPMG report, in light of the AER's Draft Decision.

Page 1 of the July 2010 KPMG report explains the purpose of that report, and recaps on the findings of KPMG's first report as follows:

> "In Section 7.5.3 of its Draft Decision on United Energy's (UED's) regulatory proposal for the 2011 Electricity Distribution Price Review, the AER expressed concerns with the substantiation of the following forecast components of UED's expenditure:
>
> - unit volumes associated with tendered services;
> - unit costs associated with services provided internally or through related parties; and
> - unit volumes associated with services provided internally or through related parties
>
> This report summarises how in an earlier report to Johnson Winter & Slattery (JWS) "United Energy Distribution Forecasting methodology for operating and capital expenditure", KPMG:
>
> - identified the sources of information that substantiate the forecast components set out above; and
> - undertook procedures to compare the forecast components used by United Energy to those sources of information.
>
> These procedures included assessing the consistency of the forecast components with:
>
> - evidence from third parties;
> - historic cost information; and
> - documents internal to UED used for UED's own management purposes.
>
> Section 5.10 of our report to JWS summarised our findings from these and our other procedures, which found among other things that:
>
> - there was a net potential overstatement of forecast operating expenditure of the order of \$2.6m in total over the five year regulatory control period, which is less than 0.5% of the total forecast operating expenditure; but

[27] KPMG, United Energy Distribution - Forecasting methodology for operating and capital expenditure, 30 November 2009'

[28] KPMG, Bases of forecasts of operating expenditure: Report for United Energy Distribution, July 2010.

- of this, there is a net understatement of about $0.7m in operating expenditure over the five year period, resulting from forecasts being inconsistent with supporting information.

These amounts are not material in the context of over $600m of forecast operating expenditure and fall well within the bounds of reasonable forecasting precision.

Our enquires and observations when compiling our report to Johnson Winter & Slattery, led us to a view that UED sought wherever possible, to corroborate the assumptions underpinning the forecasts, to maximise the base of information on which management could make and evidence reasonable judgements and to minimise the extent to which the forecasts depended solely on management judgements. UED's forecast of "internal" expenditure, is the principal area of forecast operating expenditure in which the AER would be obliged to rely on uncorroborated management judgements. However this report and our report to JWS demonstrate that the extent of this expenditure is limited and independent transparent, publicly available benchmarks suggest that UED forecasts of internal expenditure err on the side of understating efficient costs."

Importantly, in relation to the issues of applying judgment in developing forecasts, and the evidence required to substantiate expenditure forecasts, the July 2010 KPMG report states at page 2:

"Unlike ex-post financial statements, ex-ante financial forecasts are based on assumptions about future events and actions that are necessarily judgemental. While judgements may be corroborated by supporting evidence it is not possible to "prove" an ex-ante assumption on which a forecast may be based. There is general uncertainty about any forecasting assumption since no assumption of the future can ever be proved. Because of this it will always be possible to suggest that either the evidence is insufficient or that more supporting evidence could be gathered. A deterministic standard of evidentiary support is therefore not relevant to the production of forecasts in the way it might be to historical financial statements. Rather the appropriate standard is one of whether the forecasts have been properly compiled and calculated on the basis of reasonable assumptions and hence judgements.

However, in reaching its Draft Decision the AER has neither explained the substantiation for future events that it reasonably expects of UED, nor why it believes that the assumptions that underpin UED's operating expenditure forecast are unreasonable.

In particular it is not clear to us that where the aptness of a forecasting assumption is supported by information sourced internally by UED or from a related party that this suggests that the supporting information is necessarily of lesser relevance or quality. Generally one would expect that the most relevant or specific bases of information for forecasting assumptions and judgements would be sourced from within the entity making the forecast. Evidence from other parties such as benchmarks (which UED has employed) may help by corroborating such sources, but they do not substitute for them."

In relation to the AER's Draft Decision on UED's operating expenditure forecasts, the July 2010 KPMG report concludes (at page 2): as follows:

"The AER in its Draft Decision, does not accept UED's forecast expenditure components of:

- unit volumes associated with tendered services;
- unit costs associated with services provided internally or through related parties; and
- unit volumes associated with services provided internally or through related parties

on the grounds that these forecast expenditure components are insufficiently supported or that the links between the supporting source material and the forecast expenditure components are not clearly established.

It is our view that the AER's findings are inconsistent with the findings set out in our November 2009 report to Johnson Winter & Slattery which:

- provide substantiation for the components of UED's operating expenditure forecast and their links to the forecast; and
- our November 2009 report to Johnson Winter & Slattery which found that UED designed and applied a highly transparent and structured approach to developing its forecasts in accordance with the relevant requirements of the National Electricity Rules and good forecasting practice."

As evidenced by the independent expert opinion cited above, and the additional detailed information provided in sections 5.2.3 and 5.2.4 below, UED considers that its operating expenditure forecast is fully substantiated, and meets the requirements of the Rules. It should therefore be accepted by the AER.

5.2.3 Outsourced work volumes

The AER's reasons for not accepting UED's forecast outsourced unit volumes are expressed in the draft determination as follows:

> "While the unit costs associated with outsourced services have been determined via tender, the unit volumes associated with these services have been estimated by United Energy. A KPMG report submitted by United Energy states that United Energy sourced information from Jemena and internally to determine the forecast volumes of operating and maintenance work on its network.[29] However, few details are provided on this information and the information itself was not submitted by United Energy with its regulatory proposal. The AER also notes that United Energy has not provided historical volume information with its proposal nor demonstrated either how its forecasts are consistent with historical patterns, or why they differ from historical levels if this is the case. The AER considers that the forecast volumes associated with outsourced activities have not been substantiated in United Energy's regulatory proposal."[30]

5.2.3.1 Bidders submitted budgets based on prices and volumes combined

Whilst the distinction drawn by the AER between the tender price and volumes may be appealing conceptually, such a distinction is invalid in this case because the tender process determined unit prices and volumes concurrently. Importantly, the "price" offered by each tenderer was in the form of an operating expenditure budget that reflected the product of unit prices and forecast volumes. Furthermore, there was a strong incentive on UED and bidders to ensure that bids were based on the best possible information regarding expected unit prices and work volumes. This is because:

- to be successful, a tenderer must submit the lowest five-year opex budget (that is, price *times* volume for each activity); and
- the budget will determine UED's operating expenditure allowance, and therefore UED will have a very limited capacity to fund costs above the tendered budget.

UED ensured that each tenderer's operating expenditure budget offer reflected a soundly-based forecast of work volumes by:

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[29] United Energy, Regulatory proposal—Appendix C1 ('KPMG and Johnson Winter & Slattery, United Energy Distribution—Forecasting methodology for operating and capital expenditure, November 2009'), pp. 73–75.

[30] AER Victorian distribution draft decision 2011-2015, page 231

- Conducting an extended and interactive tender period (of approximately three months duration from short-listing to submission of binding offers) during which UED made all relevant information available to tenderers in relation to work volumes, current asset conditions, Asset Management Plans and Life Cycle Management Plans for each asset class; and
- Ensuring that proponents understood that the contractor will share any 'pain' associated with actual costs exceeding tendered opex budget, as described below.

The contract priced by tenderers for the purpose of the Regulatory Proposal places the contractor's entire gross margin at risk depending on cost efficiency and service quality. Subject to further adjustments for non-financial performance, the contractor bears 50 per cent of costs incurred above the annual target outturn cost (TOC) which is largely a function of the tendered "Original Opex Budget" (OOB) as follows:

> A significant element of the ... Performance Payment will be determined by... comparing Actual Outturn Cost (AOC)... to Target Outturn Cost (TOC)[31]
>
> The... Performance Payment determined in relation to financial performance (PP_{FP}) will be... where AOC is equal to or greater than TOC: PP_{FP} = (TOC - AOC) x 50%[32]
>
> [Opex element of] TOC = (EOB[33] x $Weight_{EOB}$) + (CPI-adjusted OOB x $Weight_{OOB}$)... where... $Weight_{OOB}$ = the percentage amount for the applicable Operational Year[34]

Table 5-4: Operational performance weightings

Operational Year	1	2	3	4	5	6 on
$Weight_{OOB}$[35]	80%	70%	60%	50%	40%	0%
$Weight_{EOB}$	20%	30%	40%	50%	60%	100%

Contractor margin is also tied to the achievement of comprehensive non-financial performance targets (principally the end-customer outcomes incentivised under the STIPS scheme) – for example:

> "An element of the Limb 3 Performance Payment will be determined by non-financial performance, measured by comparing various non-financial outcomes against agreed targets[36]

[31] UED OMSA ('Mallesons Stephen Jaques, United Energy Distribution—Operational and Management Services Agreement') Schedule 4 Paragraph 1.5(a-b)

[32] UED OMSA Schedule 4 Paragraph 7.3(a)

[33] EOB means "Earned Opex Budget (EOB), being the AOB adjusted to reflect actual Opex work volumes completed during that Operational Year" (UED OMSA Schedule 4 Paragraph 1.5(c)(i)(B)) where AOB means the prevailing Annual Opex Budget that "represents best available value for money in the circumstances... [and] meets the Customer's business requirements including... [expected achievement of] prevailing Non-Financial Performance Targets" (UED OMSA Schedule 4 Annexure 9 Paragraph 1(d))

[34] UED OMSA Schedule 4 Paragraph 8.4

[35] UED OMSA Schedule 4 Schedule 4, Annexure 4 – Commercial Parameters

> Performance Targets [have] been established... which the Service Provider [contractor] acknowledges to be consistent with the OOB."[37]

Hence, regardless of the method of its construction, the tendered OOB operates as a fixed dollar value for the purposes of determining the contractor's share of any cost over-runs. There is no relief for the contractor if future unit costs or volumes differ from those used to construct the tendered budget, for example if unit costs rise or additional opex is required to achieve the performance targets. Tenderers were explicitly aware of this arrangement when pricing their proposals.

UED's conditions of tender made it clear that tenderers should inform themselves and not rely on UED representations in constructing their binding offers.[38] Three of the shortlisted consortia (including the preferred tenderer) have substantial experience in electricity network operation and maintenance in Victoria, so are well-placed to assess the risks associated with actual historic operating and maintenance unit volumes and associated data provided by the current contractor.

To further assist the AER in understanding the role of work volumes in the bidding process, AT Kearney has produced a detailed explanatory paper, which will be provided to the AER on a confidential basis.

UED has also obtained a letter from Dench McClean Carlson Corporate Advisory ("DMC"), the probity auditor engaged by UED to provide probity advice in respect of the process for the procurement of Utility Operations and Management Services. That letter, dated 13 July 2010, corroborates the explanation set out above. It states:

> "The RFP provided thirteen pages of indicative volumes and metrics (mostly based on historic data) for bidders to consider in developing their competitive bids (pages 126-139) The RFP also clearly stated that bidders were responsible for making their own assessments of the information provided in the RFP (pages 42-43).
>
> Further the RFP required that "For each service area within the Service Package UED requires unit cost estimates and assumed volumes for major cost items to allow UED to compare efficiencies between respondents." (page 50).
>
> In most competitive processes the onus is on bidders to understand the business for which they are tendering and the metrics associated with that business.
>
> It is likely that the Boards of the bidders would want to be satisfied that the bid price proposed is sufficient to cover the likely costs and each bidder would need to form a view about the accuracy of the metrics to reach that conclusion.
>
> We noted the document provided by UED containing a table headed "Outsourced Services where unit volumes were estimated by the Turnkey Service Provider".
>
> We were also provided with an example where a bidder requested a change to the UED volumetric data.

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[36] UED OMSA Schedule 4 Paragraph 1.6(a)

[37] UED OMSA Schedule 4 Paragraph 9.6(a)

[38] E.g. "In submitting a response to this RFP, Respondent represents and warrants that... it has not relied on the information... made available by or on behalf of UED... it has made all necessary independent inquiries..." UED RFP ('*United Energy Distribution – Request for Proposal – Utility Operations and Management Services 8th April 2009'*) pp. 42-43

> While we would expect that UED is best placed to provide accurate historic volumes, any prudent bidder would make its own assessment of the likely volumes in the future to arrive at a commercially competitive price that does not pose a significant financial risk.
>
> From the examination of the documents we would conclude that the bidders developed their pricing using volumes which they assessed as commercially feasible - either accepting the volumes proposed in the RFP or providing their own."

A copy of the letter from DMC has been provided to the AER.

5.2.3.2 Volume plays a limited role in determining operating expenditure forecasts

Although bidders combined their volume and price estimates in their operating expenditure budget bids, volume plays a relatively limited role as explained below. This is because the prices provided by tenderers fall into two categories:

- Line items comprising a 'unitised' price multiplied by a planned volume representing repetitive work elements – for example 1,100 feeder thermographic inspections per annum with a direct cost of $445 each;
- Line items comprising services which by their nature can only be sensibly stated as a single annual unit of service (i.e. volume of 1) – for example operation of the Network Control Centre service, with a direct cost of $5,644,876 p.a.

Only 31.1 per cent of the outsourced five-year opex budget obtained through the tendering process falls into the first category.[39] This means that even if forecast unit volume information in, the impact of such error on forecast opex would be significantly diluted.

5.2.3.3 Forecast outsourced unit volumes are closely linked to actual historical volumes

As described in further detail below, UED's forecast volumes of operating and maintenance work are based on actual 2009 work volumes supplied by JAM. Under the existing OSA JAM is required to update the Asset Management Plan (AMP) annually, and implement operating and maintenance work in accordance with that plan. Given the incentives under the current fixed-price contract for JAM to minimise opex work volumes, UED manages this process carefully, with the aim of ensuring that all required work is programmed and completed by JAM. As a starting-point for the development of tendered operating expenditure budgets, UED supplied tenderers with Jemena's planned 2009 work volumes for operating and maintenance work with minor modifications in two areas only:

- Adjustments to reflect expected impact of changes in the AMP anticipated for the 2011-2015 period to reflect latest understanding of asset condition and risks; and
- Adjustments in expected volume of fault response work in line with UED's analysis of climate trends. In this context, UED notes that the tenderers' provision for fault response amounts to 5.2 per cent of the tendered opex budget.

AECOM has reviewed these adjustments and noted that overall changes from 2009 volumes are neither material nor unreasonable, as follows:

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[39] Tenix-IBM OOB [tendered Original Opex Budget] v13 091118.xls: 5-year tendered direct costs of 'unitised' opex items (rows 8-155 and 182-183) is 31.09% of the 5-year tendered direct costs for all opex items (rows 8-197 i.e. all items whether unitised or single unit items)

> "UED has provided AECOM with the Opex quantities for the years 2011-2015 which have been used to develop the operational expenditure budgets proposed for the EDPR submission. Quantities have also been provided for the 2009 calendar year for comparison. Information is provided for some 67 different operational activities... The proposed Opex quantities are, by and large, similar to those that occurred in calendar year 2009... Notable decreases and Increases in the Opex quantities for the next regulatory period are [material in six of the 67 categories]... For the remainder of the works, there is no or only a small change to the quantity of work when compared with year 2009 and, overall, quantities remain consistent with those for calendar year 2009. Comments were sought from UED [re] those items with large differences... [For the first of the six] the large [395%] increase can be explained by the abnormally small number... in the Opex for 2009... The average quantity ... proposed for the up-coming regulatory period is justifiable and in accordance with expectations... [for the second (35% decrease) and third (27% increase)]... Quantities proposed by UED are reasonable... The increases in other categories [27%, 24.8% and 13% respectively] were justified by UED on the grounds that they are responding to trend data which shows an historical small increase. In conclusion, the Opex activities identified are consistent with the activities carried out in other distribution businesses and consistent with good industry practice. UED are not proposing a material increase in Opex activity and the level of activity is justified, based on the actual activities for calendar year 2009."[40]

As discussed in the previous section, these UED-supplied work volumes are not directly relevant to the operating expenditure forecasts, as those forecasts are based on the bidders' tendered proposals, however they can be employed to compare forecast unit volumes to historic volumes.

5.2.3.4 Details of forecast outsourced unit volumes compared to historic volumes

UED notes the AER's concern regarding the absence of detailed information in UED's original Regulatory Proposal in relation to forecast volumes of operating and maintenance work; historic volume information, and information on consistency with historical patterns or reasons for any differences.

AECOM confirms that UED provided bidders with 'year 4' 2009 volumes for outsourced services. However, as explained in section 5.2.3.1 bidders made their own decisions using their experience and knowledge in the face of a competitive bidding process to determine the volumes and unit prices they used to compile their offers. UED has taken every conceivable step to comply with the AER's preferred approach to forecasting by taking account of the 2009 'year 4' volume data, and adopting a competitive tender process to determine outsourced volumes, unit prices and total costs.

A detailed comparison of current and forecast unit volumes is now provided as an appendix of this Revised Regulatory Proposal. This comparison demonstrates that forecast volumes are substantially the same as existing volumes, as noted by AECOM in its independent expert report (cited above).

UED believes that the information provided in this Revised Regulatory Proposal should enable the AER to accept UED's operating expenditure forecasts in relation to outsourced services.

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[40] AECOM Independent Expert Report – Section 6.0 ('AECOM, United Energy Distribution—UED Asset Management Plan Review, 30 November 2009'), p3.

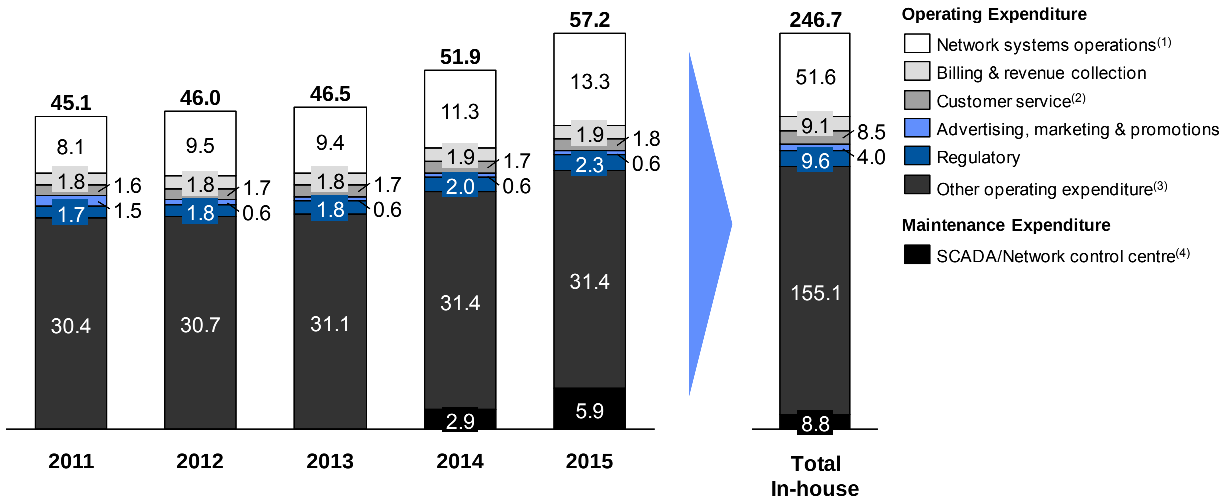
5.2.4 UED's in-house cost forecasts

In order to establish a cost forecast for UED's new business model UED needed to:

- determine the organisation and internal resource requirements for the new model; and
- use benchmark data to estimate the total remuneration expense for the new organisation.

As noted above, the AER's Draft Decision did not accept UED's in-house cost estimate "because of the significant degree of estimation involved in this forecast which has not been sufficiently supported." Before turning to the in-house "unit costs" (or labour rates) and the in-house "volume" components, it is important to recap on the composition of UED's in-house operating expenditure forecasts. This is shown below.

Figure 5-1: Total 5-year Outsourced Operating and Maintenance Forecast (real 2010$)

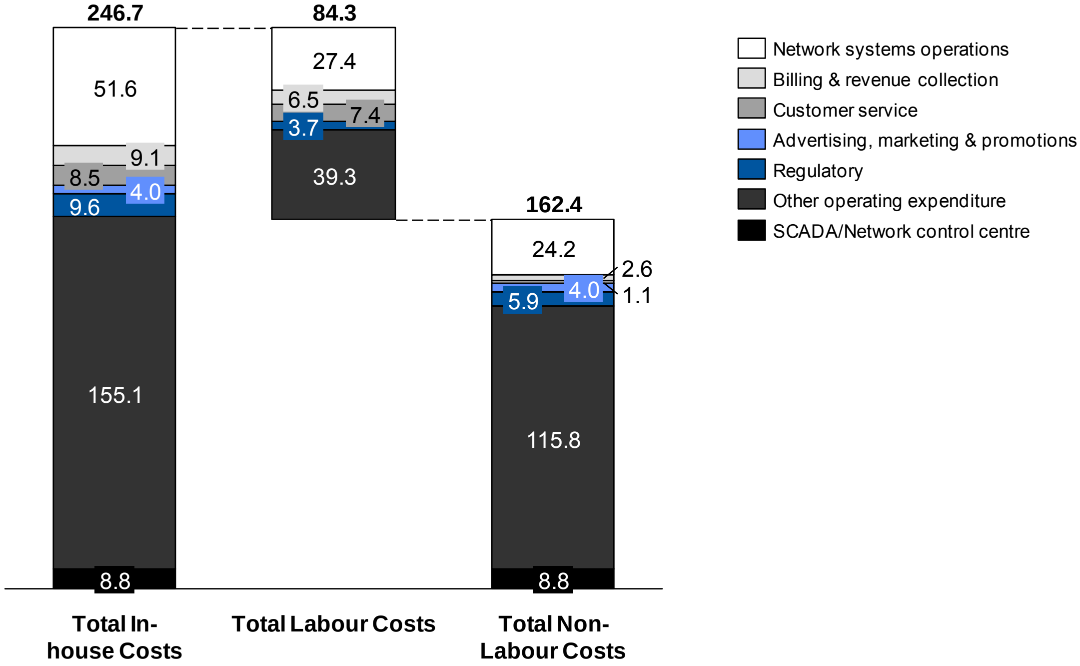


(1) Comprises of in-house Asset Management, Service Delivery, and Consortium Management (brought in-house from July 2014)
(2) Comprises of in-house Customer & Market Management function
(3) Comprises of in-house IT Management Services, Legal and Key Contract Management Services, Finance & Administrative Services, CEO Office, and Other Internal Costs
(4) Comprises of Network Control Centre (brought in-house from July 2014)

Source: UED Regulatory Proposal, 30 November 2009.

Importantly, UED's in-house costs can be broken down into two main categories – labour costs, and non-labour costs, as demonstrated in the figure below.

Figure 5-2: Total 5-year In-house Forecast Operating & Maintenance Expenditure by Labour/ Non-Labour Costs (real 2010$)



Source: UED Regulatory Proposal, 30 November 2009.

It is evident from the above figure that more than 66 per cent ($162.4 million) of UED's in-house operating and maintenance forecast is comprised of non-labour costs. It is important, therefore that the AER's examination of UED's in-house costs considers both the labour and non-labour elements. In particular, whilst it may be appropriate to examine labour costs in terms of "volume" and "unit costs", this approach is less appropriate for non-labour costs, which include items such as accommodation, rates, and rent. UED has therefore adopted this breakdown in sections 5.2.5, 5.2.6 and 5.2.7 below.

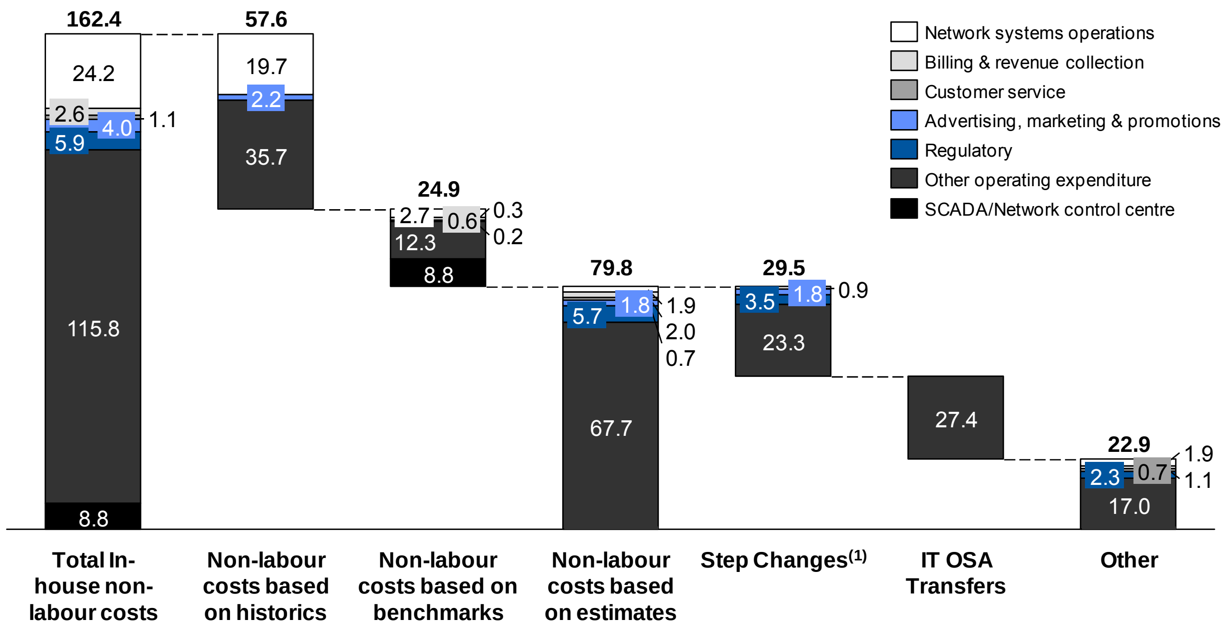
5.2.5 UED's in-house non-labour cost forecasts

As noted above, UED's original Regulatory Proposal included an independent expert opinion from KPMG on UED's forecasting methodology. In relation to UED's in-house non-labour costs, KPMG assessed and confirmed the amounts forecast for these costs, grouped broadly into the following three categories:

- Non-labour cost estimates based on historic data, escalated to real 2010 dollars;
- Non-labour cost estimates based on "available comparative cost information" and benchmarks; and
- Non-labour cost estimates based on estimates from UED management and the independent expert consultants engaged by UED.

The following figure provides this further breakdown of UED's in-house non-labour costs, indicating that the majority of UED's in-house non-labour costs are substantiated with reference to historic data or benchmarks.

Figure 5-3: Total 5-year In-house Non-Labour Operating & Maintenance Forecast (real 2010$)



(1) Includes $17.7 M of self insurance provision (refer to section 5.5.12 of UED's Regulatory Proposal) and $5.6 M of debt raising costs, and other step changes (refer to Appendix B-7 of UED's Regulatory Proposal).

Source: UED Regulatory Proposal, 30 November 2009.

Further information analysing UED's non-labour costs is provided in a report from AT Kearney, which is to be provided to the AER on a confidential basis. AT Kearney's report highlights important findings from KPMG's expert opinion that are relevant to demonstrating the veracity of UED's in-house non-labour cost estimates. In UED's view, this information fully substantiates UED's in-house non-labour forecasts.

5.2.6 In-house labour rates

As outlined in section 6.6.4 of the draft decision, the AER has stated that "while United Energy has submitted [economy-wide and utility industry salary benchmark] reports…, it has not clearly demonstrated the link between the reports and the salary estimates in its internal corporate budgeting model."[41]

The AER has also noted that "the reports were not commissioned by United Energy in the context of its business transformation or regulatory proposal but rather reports which are published regularly by recruitment firms".[42]

In determining salary estimates, UED used both:

- publicly available economy-wide salary benchmark reports, such as:

[41] AER Victorian Distribution Determination 2011-2015 – Draft Decision, p. 232

[42] AER Victorian Distribution Determination 2011-2015 – Draft Decision, p. 232 (footnote 36)

  - Hays Sector Commentary 2009
  - Hudson Salary Guide 2009
  - Michael Page Salary & Employment Forecast 2009; and

- a utilities industry salary benchmark report that was commissioned by UED:
  - Geoff Nunn & Associates' Survey of Market Remuneration in the Power, Water & Utilities Sector in Australia – April 2009.

The Geoff Nunn & Associates Survey is the most comprehensive survey of remuneration in the Power, Water & Utilities Sector in Australia. The analysis provided in this survey is based on data contributed directly by 53 organisations, together with data for a further eight organisations sourced from Annual Reports and other publicly available information. Fifty-seven per cent of the survey participants are in the Electricity & Gas industry, and thirty-six per cent of the above survey participants are based in Victoria.[43]

For roles that are specific to the utilities industry, such as Asset Management and Customer & Market Management roles, UED based its salary estimates on the 2009 Geoff Nunn & Associates' Survey. For all other roles, such as those in Legal and Key Contract Management, Finance & Administration, and CEO Office, UED based its salary estimates on all four salary benchmark reports where the salary benchmark was available and/or appropriate.

As noted above, UED also engaged KPMG to provide an independent expert opinion on the design and application of UED's forecasting methodology for operating and capital expenditure. KPMG reviewed a sample of 30 salary costs and concluded that:

> "…the assumptions of positions and employment costs that underpin UED forecasts of internal expenditure have a supportable basis and are consistent with UED's assumptions of its business model for the 2011-2015 Regulatory Period."[44]

As also noted above, UED is to provide the AER with a confidential report from AT Kearney. This report presents detailed tables that demonstrate the linkage between the salary benchmark reports and the salary estimates used in UED's Regulatory Proposal. The salary estimates are grouped into three categories:

- Salary estimates based on current remuneration package, as these employees are current UED staff;
- Salary estimates based on 2009 Geoff Nunn & Associates' Survey of Market Remuneration in the Power, Water and Utilities Sector, as these roles are industry-specific; and
- Salary estimates based on various economy-wide and utility industry salary benchmark reports, such as Hays, Hudson, Michael Page and Geoff Nunn & Associates.

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[43] Geoff Nunn & Associates website, http://www.gna.net.au/utilitiessurvey_001.htm

[44] KPMG Independent Expert Report – Section 5.4.3 ('*KPMG, United Energy Distribution—Forecasting methodology for operating and capital expenditure, 30 November 2009*'), p.76

The AER's Draft Decision also criticised UED's labour cost forecast on the basis that it included a 15 per cent salary bonus for most staff which had not been explained or substantiated."[45]

UED notes that the bonus ranges for current UED employees are:

- 10 per cent to 20 per cent of the annual salary for most staff; and
- 5 per cent to 10 per cent of the annual salary for administrative and clerical staff.

Depending on the type of role and the performance evaluation of the individual, UED has assumed a 15 per cent salary bonus for most staff and a 7.5 per cent salary bonus for administrative and clerical staff. UED considers this estimate to be reasonable.

UED believes that the information provided by UED, including the confidential report from AT Kearney, comprehensively demonstrates that UED's in-house labour costs are reasonable and comply with the requirements of the Rules.

5.2.7 In-house labour volumes

UED assessed its resource requirements for the new business model during 2009, in accordance with the process detailed in the figure below.

[45] AER Victorian Distribution Determination 2011-2015 – Draft Decision, p. 232

Figure 5-4: The Development of UED's 7/11 Organisation and Internal Resource Requirements

	Business Model Design	Preliminary Organisation Design	Detailed Functional Reviews - TCE Process	Integrated Business Sign-off
Activities	• Using a 'Make Vs Buy' framework[1] UED determined what services should be 'insourced' for the new business model • To do this, consideration was given to - Identifying how each service exists - Clarifying complexities of interdependencies - Understanding strategic direction of the organisation • For each service or function UED performed: - Strategic assessment - Operational Assessment - Financial Assessment - Improvement Assessment	• UED conducted workshops with functional heads to determine the resource requirements for an Interim Organisation for the period between July 2009 and January 2011 in order to build capability to transition to the new business model • To provide context for the Interim organisation a Preliminary 7/11 Organisation Design and Structure was developed based on: - UED Management experience & industry knowledge - Scope of services to be 'insourced' as indicated in the 7/11 RFP	• The TCE Stage[2] involved a series of workshops and data & knowledge exchanges between UED & TCE providers • Each Functional Tower worked closely with TCE providers to detail future business model and organisation requirements for both the service providers and UED • During this process it was jointly agreed that to deliver optimal business outcomes it would be necessary to bring additional scope 'in-house' and that UED would need to increase resourcing in certain areas from the preliminary estimates in June • Proposed organisation structures and resource requirements were benchmarked against: - European Utility benchmarks - JAM 2009 Org Structure - UED 1999 Org Structure (pre-OSA)	• A workshop with each of the functional areas was conducted to provide the opportunity for a cross-functional and integrated assessment and evaluation of the individual functional organisation structures that had been developed through the TCE process • Key interfaces between the functions were tested, and a 'whole of business' view presented, analysed and compared with future business requirements • Comparisons were made with UED management's knowledge of other Australian distribution businesses and the proposed structure • Any necessary adjustments to the organisation structures for each functional area were made, and the total business Resource Plan was signed-off
Output	• 7/11 Business Model Design	• 7/11 UED Interim Resource Plan, June 2009		• 7/11 UED Resource Plan (November 2009)

(1) (2) The UED Make Vs Buy Framework and the TCE stage have been outlined in July and November Board papers previously presented to the AER

Table 5-5 below provides an overview of UED's 7/11 Organisation by each functional tower, including the removal of allocations for capitalised costs related to personnel directly or indirectly involved in the delivery of the UED capex program.

Table 5-5: UED Internal Resources as at June 2012

Function	Total Employees (1)	Less Capitalisation	Net UED DUOS OPEX
	FTE	FTE	FTE
Asset Management	32.6	11.5	21.1
Service Delivery	8.5		8.5
Customer Management	15.0		15.0
Information Technology	15.7	6.0	9.7
Finance & Admin	23.9	1.6	23.3
Regulatory Services	3.8		3.8
Legal & Key Contract	7.6		7.6
CEO Office	12.2		12.2
TOTAL	120.3	19.1	101.2

(1) Excludes Multinet, Metering and proposed 6 contract staff
Source: UED's *"Budgeting Model – Corporate – 5 Year – 091112"*

Table 5-6 below provides an overview of UED's 7/11 Organisation and the supporting evidence that has been used to estimate the required headcount.

Table 5-6: Supporting Evidence for the UED 7/11 Organisation FTE Headcount

Function	No. of Employees(1)	Supporting Evidence
Network Management		
Asset Management	22.6	**UED Historic Data**[46] The team of 23 is roughly equivalent to the team of 22 who performed the Asset Management role for UED in 1999, prior to the commencement of the OSA, at which time this function was outsource to JAM.
Compliance and Environmental Management	7	**JAM Current Organisation**[47] The Compliance and Environmental Management Team of 7 FTEs is comparable with the estimated 6.4 Compliance staff currently working at JAM who are allocated to the UED network
Occupational Health & Safety	2	**JAM Current Organisation** The OH&S team of 2 employees also compares favourably with the estimated 2.1 OH&S FTEs currently working at JAM who are allocated to the UED network.
Risk Management	1	**JAM Current Organisation** UED has determined that 1 Risk Manager will be required to maintain and monitor corporate wide risk management; this role is also currently provided by JAM for UED, although the role sits within the Finance organisation in JAM (and not Operations, as is the plan for the UED 7/11 organisation).

[46] UED's 1999 Organisation Charts have previously been supplied to the AER

[47] UED's 7/11 Organisation Charts

Function	No. of Employees[(1)]	Supporting Evidence
Service Delivery Management	9	**Management & Expert Estimates** The team size for each of the regions was determined in the TCE stage, where the interface and performance management requirements for each of the network service provider was analysed extensively. Each team is required to actively manage services to the value of $150M per region per year, ensure contractual performance is delivered and costs claimed match services.
Customer & Market Management		
Market Services & AMI Systems Management	9 (4 roles in DUOS Opex; 5 roles in Metering Services, not included in the EDPR Submission)	**UED Historic Data** The team of 9 is broadly consistent with the team of 7 who performed these roles at UED when this service was provided in-house in 1999 prior to the execution of the OSA. The increase in resource requirements from this period is in part due to the incremental complexity in the Business to Business interface, increasing retail competition, increased number of retailers and the disaggregation of retail from the distribution business.
Stakeholder Relations Management	11	**JAM Current Organisation** The number of resources that UED has allocated to these functions is equal to what is currently the case in JAM, which has a total of 9 FTEs in Stakeholder Relations and Key Customer Management and 1 x Facilities Manager and 1 x Network Account Manager.
IT		
IT Strategy / Architecture Management	7.75	**UED Historic Data** The team of eight is half the size of UED's planning and architecture team in 2002.
Portfolio Management	4	**Management & Independent Expert Estimates** UED's IT Capex program for the 2011-2015 period contains on average 15.3 projects per year. The team of 4 will need to cover all activities required to scope, coordinate and manage the delivery of these projects by the appointed service providers for each project.
IT Service Delivery/ Contracts Management	4	**Management & Independent Expert Estimates** Team size is largely driven by the different functional disciplines – one finance, one reporting and two operations managers (one senior, one junior) for reviewing vendor performance, addressing issues the business may have with IT and resolving any performance issues.
Corporate Services		
CEO	1.2	**Existing employees** CEO and Executive Assistance to CEO
Finance	20	**UED Historic Data / Management & Independent Expert Estimates** For the total finance team (including Finance, Debtor Management, Revenue Management and Planning and Analysis) of 20 people is approximately 3.5% of total FTEs (within the UED network), and is comparable to organisation and industry benchmarks. This number is less than 60% of the 35 Finance employees at UED in 1999.
Administration	5	**Management & Independent Expert Estimates** The Administration staff of 5, including company secretary, registry, receptionist and two administrative employees for the entire office, is approximately is less than 1% of total FTEs (within the entire UED network). KPMG has reviewed the structure and found that the assumptions of the staffing structure are consistent with their understanding of the minimum required for a distribution business of UED's size.[48]
Strategy & Business Development	5.5	**UED Historic Data** The team of 5.5 is less than half the size of the 12 staff responsible for corporate / business development and corporate communications activities in the pre-OSA UED organisation
HR & Organisational Development	5.5	**JAM Current Organisation / Management & Independent Expert Estimates** JAM currently have 18 staff in the HR area supporting UED, many however are not full time. The full time equivalence is estimated at 3 people. There is some dis-synergy given the mix of administration and functional expertise to be covered. The role will be particularly demanding over the coming years as the organisation grows quickly and new staff, policies and practices need to be embedded.

[48] KPMG Independent Expert Report – Section 5.4.3 ('*KPMG, United Energy Distribution—Forecasting methodology for operating and capital expenditure, 30 November 2009*'), p.75

Function	No. of Employees(1)	Supporting Evidence
Legal & Commercial Contract Management	6.6	**JAM Current Organisation** JAM's has 6 full time equivalent staff fulfilling these roles for UED at present. JAM has a legal team consisting of 13 legal staff, with 2 full time equivalent dedicated to UED business. JAM also has 2 full time equivalent contract managers supporting the UED business as well as 2 procurement staff working part time on UED business. This resource base under the OSA is complemented by one internal UED legal counsel and regular external legal support. While the management of a larger number of service provider contracts under the new business model does increase the need for additional resources in Legal and Contract Management, any slight increase in costs in this area is more than offset by the efficiencies of the proposed business model, as outlined in Section 3 above.
Regulatory Services	5	**UED Current Organisation** In 2008 the regulatory activities (team of four staff) were brought back in house from JAM and the OSA contract terms amended accordingly. Based on a forecast of resources required to provide the necessary support to the business and information required by regulators the number of personnel transferred from JAM was deemed insufficient to perform at the required level. Active participation and timely responses are the key objectives in regulatory consultation - additional resources will assist in these objectives.

(1) Represents the number of UED FTE equivalent (i.e. excludes Mulitnet)
Source: UED EDPR Submission, 30 November 2009; UED Internal Corporate Model

In addition, KPMG conducted an independent expert review of the staffing structures and FTE headcount and have concluded that:

> …the assumptions of staffing structures are consistent with our understanding of the minimum functions that would be required for a distribution business UED's size operating under UED's business.[49]

UED has previously provided the AER with a detailed description of the labour resource requirements that were developed through the above process. To assist the AER further, AT Kearney's report provides a further detailed account of UED's internal labour requirements. UED considers that this further information, together with the earlier submissions, provides an appropriate level of substantiation of UED's internal labour cost requirements.

5.2.8 UED's conclusions regarding the AER's criticisms of UED's forecasts

The information presented above supplements and explains the information provided by UED in its original Regulatory Proposal regarding the company's operating expenditure forecasts. In presenting this additional information, UED has responded directly to each of the concerns expressed in the Draft Decision regarding UED's operating expenditure forecasts.

UED considers that the information it has presented substantiates fully the company's operating expenditure forecasts in accordance with the requirements set out in the Rules. In particular, UED has provided ample evidence to demonstrate that its forecast of operating expenditure reasonably reflects:

- the efficient costs of achieving the operating expenditure objectives; and

[49] KPMG Independent Expert Report – Section 5.4.3 ('*KPMG, United Energy Distribution—Forecasting methodology for operating and capital expenditure, 30 November 2009*'), p.75

- the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In accordance with the provisions set out in clause 6.5.6 of the Rules, the AER must accept UED's forecast of operating expenditure.

5.3 UED's response to the AER's forecast operating expenditure

5.3.1 Introduction

Section 5.2 above responded to the AER's criticisms of UED's forecast operating expenditure for the forthcoming regulatory period, and concluded that UED has demonstrated that its operating expenditure forecast meets the requirement of the Rules.

As previously explained, the AER's Draft Decision concluded that UED's operating expenditure forecasts should not be accepted, and instead the AER developed its own alternative forecast based on the 'year 4' roll forward model.

UED has obtained an independent expert opinion from Philip Williams of Frontier Economics to provide an interpretation and explanation of the Rules requirements in relation to operating expenditure forecasts. In his expert opinion, Philip Williams made the following comments regarding the AER's approach to assessing UED's operating expenditure forecasts[50]:

> "In my view, the best approach for the AER to adopt in assessing whether UED's forecast operating expenditure is efficient is through some form of benchmarking analysis.
>
> As noted above, benchmark operating expenditures are one of the operating expenditure factors that the AER must have regard to when assessing whether a DNSP's proposed operating costs meet the requirements of Rule 6.5.6(c) (see Rule 6.5.6(e)(4)). As also noted above, I think that in light of the unsustainability of the costs under UED's present OSA with JAM, more weight should be placed on benchmarking to derive forecast operating expenditure than on UED's (or JAM's) historical costs.
>
> Accordingly, I think that the AER should put less weight on its current extrapolation approach and focus on a proper cost benchmarking exercise for UED. The AER should seek to estimate the operating costs that an efficient and prudent operator facing UED's network conditions would incur over the 2011-2015 regulatory control period.
>
> However, I note that undertaking a robust benchmarking assessment is a difficult process. Doing benchmarking properly requires many different variables to be taken into account. If some variables are not taken into account, the results of a benchmarking exercise can be misleading.
>
> In my view, the AER's benchmarking analysis in Appendix I of its Draft Decision and noted above does not go far enough to allow the AER to properly assess whether UED's forecast operating expenditure is efficient. The AER itself concedes that the data used in its analysis

[50] Philip Williams, Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery, July 2010, paragraphs 66 -73.

> have not been corrected for differences in regulatory environment, asset classifications, network maturity and geographical factors. In addition, the AER's findings in its draft decision on the Queensland DNSPs also appear too limited to come to firm conclusions, although they do show UED to be significantly more efficient than most DNSPs in the NEM.
>
> Keeping these caveats in mind, I note that on their face, per customer revenues of DNSPs in Victoria appear to be significantly lower than per customer revenues for DNSPs in New South Wales and this seems to be in part the result of lower operating expenditure per customer by Victorian DNSPs. This difference in expenditures may be due to non-efficiency reasons, but the AER's analysis does not show this to be the case. In this context, I find it odd that the AER has rejected UED's operating expenditure forecast as not reflecting efficient and prudent costs.
>
> Ideally, I consider that a proper benchmarking exercise would involve consideration of the nature, size and growth of UED's network over the relevant period compared to other similar network businesses in Victoria and other NEM jurisdictions. In my view, this is the best way of ensuring that the AER's estimates satisfy the requirements of Rule 6.5.6(c).
>
> To the extent that the AER continues to place weight on its extrapolation of costs approach, the AER will in some cases need to either amend its approach or justify its adoption of assumptions different from those made by UED in its regulatory proposal. In particular, as contended above, the AER should not necessarily assume that UED could and should renew the current OSA with its current price structure."

UED strongly concurs with Philip Williams' opinion. In particular, Philip Williams concludes that if the AER continues to place weight on its year 4 approach it is appropriate for the AER to either amend its approach or justify its adoption of assumptions different from those made by UED in its Regulatory Proposal. In this section, therefore, UED examines the AER's 'year 4' method and makes appropriate adjustments to correct for errors and omissions in the AER's approach. In UED's view, a corrected 'year 4' method should satisfy the following requirements:

- A valid base year cost estimate must be derived for the purpose of developing a "rolled-forward" estimate of expenditure.
- Once a valid base year cost is established it must be rolled forward with appropriate adjustments to reflect changes in output quality and quantities, changes in the real prices of inputs, and other factors.

It is noted that UED's 'reference line' calculation in its original Regulatory Proposal projected 2008 audited costs to 'stress test' UED's operating expenditure forecasts. UED accepts that the AER's 'year 4' method could also be used in a similar manner, even though it cannot provide a reasonable forecast of UED's operating expenditure because UED's new business model is a marked departure from existing arrangements.

The table below summarise the derivation of the base year costs and the rolled forward operating expenditure for the forthcoming regulatory period, using the AER's 'year 4' method with correct data inputs. It demonstrates that a properly constructed 'year 4' approach results in operating expenditure that exceeds the operating expenditure that UED will incur under its new business model. This confirms that UED's decision to adopt its new business model is soundly based.

Table 5-7: Derivation of valid base year costs for the roll-forward model

(Note the derivation of base year costs are provided as a confidential appendix).

Table 5-8: UED's updated version of the AER's 'year 4 roll-forward' operating expenditure forecasts ($M in 2010 dollars)

Element and reference	YEAR ENDING 31 DECEMBER					Total
	2011	2012	2013	2014	2015	
Base year costs	106.3	106.3	106.3	106.3	106.3	531.5
Escalation for growth	0.8	1.6	2.4	3.2	4.0	12.0
Escalation for price charges	2.0	3.0	4.2	5.9	6.9	22.0
Step changes	15.7	14.9	13.3	13.3	13.3	70.5
GSLs	0.3	0.3	0.3	0.3	0.3	1.5
Self insurance	3.5	3.5	3.5	3.5	3.5	17.5
Demand management incentive scheme[51]	0.7	1.8	2.5	2.5	2.5	10.0
Debt raising	0.1	0.8	0.9	0.9	1.0	3.7
Total	**129.4**	**132.2**	**133.4**	**135.9**	**137.8**	**668.7**

Sections 5.3.2 to 5.3.8 below provide detailed information to explain and substantiate the data presented in the tables above.

5.3.2 Establishing appropriate base year costs

5.3.2.1 Introduction

An important aspect of the 'year 4' forecasting method is the establishment of efficient base year costs from which forecast operating expenditure is rolled forward. The Draft Decision explained that[52]:

> "..the AER has determined United Energy's base year opex on the summation of two sources:
>
> - JAM's costs in 2008 of servicing United Energy's network, as reported by JAM to United Energy and verified by PriceWaterhouseCoopers (PWC) (subject to the exclusion of certain cost categories allocated to United Energy, as discussed in sections 6.7.1 and 6.7.3). The AER notes that these PWC reports are the starting point used by United Energy to complete its regulatory accounting statements and the AER considers these reports reliable. Further, these costs do not include transitional costs associated with United Energy's new business model.
> - United Energy's 2009–10 internal costs as provided in its internal corporate opex budgeting model, with the costs associated with its new business model removed. While

[51] Refer to Chapter 18 for information on the Demand Management Incentive Scheme.

[52] AER, Draft Decision, pages 239 and 240.

these costs are estimates, they have the benefit of being a bottom up construction from individual cost categories. Accordingly, the AER has been able to review the model line-by-line and remove transitional costs and other costs associated with United Energy's new business model.

The AER did not include within this base year estimate the management and financial services fees that United Energy forecasts it will pay its related parties (DUET and AMP Capital Investors) over the forthcoming regulatory control period. The AER's reasons for this exclusion are set out in section 6.7.1.

The AER will update United Energy's base year costs for its final decision following consideration of JAM's 2009 costs of servicing United Energy's network."

In constructing its estimate of UED's operating expenditure requirements, the AER made a number of adjustments to UED's base year costs. The remainder of this section sets out UED's position on the adjustments that UED considers should be made in order to establish an appropriate base year cost, and is structured as follows:

- Section 5.3.2.2 substantiates the costs of services provided by DUET and AMPCI;
- Section 5.3.2.3 deals with the removal of non-recurrent costs;
- Section 5.3.2.4 deals with the AER's removal of the audited transfer between capital and operating expenditure as set out in UED's regulatory accounts;
- Section 5.3.2.5 deals with the AER's assumption regarding the change in UED's operating expenditure between 2009 and 2010;
- Section 5.3.2.6 establishes an appropriate margin on the cost incurred by JAM in providing outsourced services to UED; and
- Section 5.3.2.7 establishes the correct CPI to escalate 2009 cost data to 2010.

Each of these matters is addressed in turn below.

5.3.2.2 Services provided by DUET and AMPCI

In relation to the removal of the fees paid to DUET and AMP Capital Investors, the AER summarised its concerns as follows[53]:

"Based on the limited amount of information provided by United Energy, the AER is not satisfied that the management fees paid to DUET reasonably reflect efficient costs that would be incurred by a prudent operator in the circumstances of United Energy. Accordingly, the AER has not included these fees in its estimate of United Energy's opex forecast."

"UEDH also sources treasury and financial services from AMP Capital Investors (AMPCI). The AER has reviewed the contract and considers that there appears to be a substantial overlap between the services provided under this arrangement and the separate debt raising costs allowance sought by United Energy in its regulatory proposal. Given this 'double-counting' of costs within United Energy's expenditure forecasts, the AER is not satisfied that the inclusion of these financial services fees in addition to the separate debt raising costs allowance within United Energy's opex forecast reasonably reflects efficient costs that would be incurred by a prudent operator."

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[53] AER, Draft Decision, pages 202.

In relation to DUET, the AER also noted that these management fees had not been market tested[54]:

> "United Energy's regulatory proposal only states that these fees are for 'management and investment services to UEDH' and that DUET plays an 'important role' in the management of UED. It states that DUET provides oversight and management of investors' capital and incurs a range of related corporate governance and regulatory compliance costs.
>
> However, United Energy's regulatory proposal:
>
> - does not explain why United Energy choose to outsource this service and why its own management team (including the UEDH and PIES management staff) were not capable of providing these services themselves;
> - does not explain the process under which the services were procured (for example, whether the services were procured using a competitive tender)
> - does not explain how the fee is calculated and how this relates to the underlying costs of DUET
> - does not clearly explain the amount of the management fees which are included in its expenditure forecasts, and
> - does not include a copy of the contract."

UED accepts the AER's criticism that UED's original Regulatory Proposal did not provide sufficient explanatory information regarding the services that are provided by AMPCI and DUET. The following explanation and cross-references to appendices in this Revised Regulatory Proposal should address the AER's concerns.

In relation to AMPCI, UEDH obtains treasury and financial services in accordance with a Financial Services Agreement (FSA). The types of services provided to UEDH by AMP Capital Investors are set out in schedule 1 of the FSA, with an explanation of the fees provided in schedule 2. The services are as follows:

- Financial services (treasury).
- Transaction services associated with capital raisings by the Company. These services are advisory in nature.
- Additional services, not necessarily related to financing issues. Payments for additional services are made according to hourly rates.

The services provided by AMPCI are not remunerated through the debt raising allowance provided by the AER, which does not encompass the operating expenditure associated with routine treasury services. The treasury services provided by AMPCI are defined to include the activities described below are not related to particular debt raising activities:

- Drafting and negotiating financing documentation.
- Debt compliance advice and reporting, including treasury reports containing information as agreed.
- Liaison with ratings agencies.

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54 AER, Draft Decision, pages 201.

- Providing treasury and economic information.
- Developing and reviewing capital structure and financing strategies.
- Developing and reviewing interest rate and currency hedging strategies.

UED has obtained an independent opinion from KPMG regarding the treasury management services delivered to UED by AMPCI[55]. KPMG's report provides information on the services provided by AMPCI to UED, to assist the AER to assess whether those services are classified as debt raising services (as defined by the AER) or whether the services constitute day to day treasury management and general financial services. KPMG's report (which is provided as an Appendix to this Revised Regulatory Proposal) concludes that the services provided by AMPCI to UED under the FSA are necessarily required by UED and do not comprise debt raising costs.

The information set out above demonstrates that the services provided by AMPCI are unrelated to direct debt raising costs, and that a separate allowance for the costs of these services should be included in UED's operating expenditure forecast. As previously noted, the fees which UED pays for these treasury services are fixed at $250,000 per annum, indexed annually in accordance with movements in the consumer price index. As noted in KPMG's report, this fee equates to an amount of $321,000 expressed in 2010 dollars.

In relation to DUET, UED does not accept the AER's comments that UED's original Regulatory Proposal did not provide any explanation of the services that UED obtains from DUET. In particular, UED's original Regulatory Proposal explained that[56]:

> "The third main category of expenditure (denoted as "shareholder costs" in Figure 5-1) relates to functions undertaken, by UED's parent, DUET. DUET is an Australian-listed company with significant management capability, and it provides UED with a range of management support services. DUET holds investments in, and provides similar services to a number of different utilities. UED is therefore able to access DUET's expertise at costs that are lower than would otherwise be incurred by UED in providing such services within the business. DUET recovers the costs of its services to UED by way of a management service fee. Costs are included in UED's operating expenditure forecasts in respect of the following services provided by DUET:
>
> - general management and corporate governance support;
> - corporate strategy and planning;
> - corporate relations and stakeholder management;
> - risk and quality management;
> - treasury management;
> - regulatory management;
> - overseeing operations, network planning and investment decision making; and
> - contract management, including the OSA between UED and Jemena.

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[55] KPMG, United Energy Distribution, Treasury services delivered to United Energy by AMP Capital Investors, July 2010.

[56] UED's Regulatory Proposal, page 51.

In addition to the above explanation, KPMG's independent expert opinion on UED's forecasting methodology specifically commented on DUET and AMPCI costs[57], and confirmed that the costs were allocated appropriately.

UED has obtained an independent opinion from KPMG regarding the services delivered to UED by DUET[58]. KPMG's report explains and evidences the nature and necessity of the services provided by DUET to UED. The report concludes that services provided by DUET to UED are consistent with the requirements of a prudent operator in the circumstances of UED acting efficiently. The KPMG report also evidences the efficiency of the quantum of UED's forecast non-network operating expenditure, of which the forecast DUET service costs are an integral part.

In addition to the two KPMG reports referred to above, UED is providing the following information to the AER to substantiate the inclusion of these costs in the base year operating expenditure:

- A copy of a letter from DUET detailing the services that are provided by DUET to UED is provided as an Appendix to this submission.
- A copy of the Financial Services Agreement between UED and AMPCI for the provision of services by AMPCI is provided as an Appendix to this submission.
- An audit opinion from Ernst & Young, confirming the costs incurred by UED in relation to services provided by DUET and AMPCI, is provided as an Appendix to this submission
- This submission contains an opinion (attached as an appendix) from KPMG that the costs incurred by UED in relation to services provided by DUET and AMPCI relate to the provision of standard control services and properly fall within the definition of operating expenditure defined by the Rules. KPMG's opinion also confirms that there is no double counting of these costs with any other regulatory allowance.

UED considers that the above information demonstrates that the services provided by AMPCI and DUET are appropriately incurred in the provision of standard control distribution services. UED notes that the AER's Draft Decision raises a further set of concerns relating to whether the services could be provided more cost effectively by UED's management, and whether the services have been market tested. In response to these concerns, UED comments as follows:

- UED did explain why it chose to outsource this service and why its own management team (including the UEDH and PIES management staff) were not providing these services themselves. DUET holds investments in, and provides similar services to a number of different utilities and UED is therefore able to access DUET's expertise at costs that are lower than would otherwise be incurred by UED in providing such services within the business. UED has obtained services from DUET and AMPCI on this basis for 7 years and it would be inefficient by comparison to use in-house staff to provide these services;

[57] KPMG, United Energy Distribution, Forecasting Methodology for Operating and Capital Expenditure, November 2009, page 82

[58] KPMG, United Energy Distribution, Services delivered to United Energy by DUET, July 2010.

- The services are specialised financial services, provided by highly experienced professionals and unrelated to the technical aspects of UED's distribution business. UED has a deliberate policy to minimise administrative overheads and has concluded that these services are more efficiently provided by the external specialists;
- UED is not under any obligation to 'market test' services, and UED notes that the AER does not expect other distributors in Victoria or other jurisdictions to routinely market test its services;[59] and
- It should be noted that the 'year 4' roll forward methodology assumes that the revealed costs are efficient, and on this basis the existing costs incurred by UED in relation to the services provided by AMPCI and DUET should be accepted by the AER as efficient.

5.3.2.3 Removal of non-recurrent costs

The AER's Draft Decision explained that it has made a number of adjustments to UED's costs in order to remove costs associated with the new business model or costs that the AER considers to be 'non recurrent'. The AER explained its approach as follows[60]:

> "Accordingly, the AER has determined United Energy's base year opex on the summation of two sources:
>
> JAM's costs in 2008 of servicing United Energy's network, as reported by JAM to United Energy and verified by PriceWaterhouseCoopers (PWC) (subject to the exclusion of certain cost categories allocated to United Energy, as discussed in sections 6.7.1 and 6.7.3). The AER notes that these PWC reports are the starting point used by United Energy to complete its regulatory accounting statements and the AER considers these reports reliable. Further, these costs do not include transitional costs associated with United Energy's new business model.
>
> United Energy's 2009–10 internal costs as provided in its internal corporate opex budgeting model, with the costs associated with its new business model removed. While these costs are estimates, they have the benefit of being a bottom up construction from individual cost categories. Accordingly, the AER has been able to review the model line-by-line and remove transitional costs and other costs associated with United Energy's new business model."

In addition to removing costs associated with the new business model, the AER has removed costs that it has identified as non-recurrent costs incurred by Jemena in providing outsourced services to UED. The AER assumed that UED has also incurred the same non-recurrent costs in 2009, although the AER did not provide sound evidence for this assertion[61]:

> "Importantly, the AER notes that the additional cost categories identified by Jemena reflect the non-recurrent costs proposed in its regulatory proposal. Given the comparability of these

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[59] UED notes, for example, that the AER made no mention whatsoever of "competitive" or "market" testing in respect of any aspect of the NSW distributors opex costs, the overwhelming majority of which are incurred by internal resources.

[60] AER, Draft Decision, pages 239

[61] AER, Draft Decision, page 245.

costs with United Energy's 'other' costs category, the AER considers that the other cost category proposed by United Energy also reflects expenditure which is non-recurrent. Accordingly, the AER has excluded non-recurrent expenditure, totalling [c-i-c][62] million ($2010), from United Energy's base year level of opex. This expenditure reflects the percentage of JAM's non-recurrent expenditure allocated to United Energy."

The costs removed by the AER form part of the audited costs incurred by JAM in providing services to UED, and there is no basis for the AER's assertion that these costs are non-recurrent. Moreover, UED has previously noted that it is inconsistent with the Rules requirements for the AER to remove efficient costs that UED expects to incur in its new business model simply because the AER wishes to adhere to a mechanical 'year 4' forecasting methodology.

A related issue arises in relation to the AER's treatment of transformational costs, which UED will incur as it transitions to its new business model. The AER makes two observations regarding these transformational costs. The first comment relates to the inclusion of these costs in UED's operating expenditure forecasts, and the second relates to UED's inclusion of these costs in its reference line calculation[63]:

> "In addition to the above, United Energy also seeks to recover the forecast transformational costs associated with the move to its new business model. These transformation costs include the upfront costs of implementing new business processes and systems, and meeting the costs of redundancies associated with gaining efficiencies. The AER notes that United Energy's modelling appears to mistakenly include the forecast transformational costs from the first six months of 2016, which is beyond the forthcoming regulatory control period."
>
> "The 'base year' estimate from which the reference line is forecast overstates the costs United Energy would incur under the continuation of its current business model due to the inclusion of transformational costs currently being incurred by United Energy in transitioning to its new business model."

Philip Williams of Frontier Economics has commented specifically on these issues in his independent expert opinion as follows[64]:

> "On the issue of transformational costs, I agree with the AER that it is inappropriate to include these costs in the determination of the business-as-usual reference line comparator, given that these costs would not be incurred if the previous business model had been retained. Therefore, these costs should be excluded from the reference line.
>
> However, I believe that UED should be entitled to recover any forthcoming regulatory period costs arising from the adoption of a new business model where that model leads to overall operating expenditures that reasonably reflect efficient and prudent costs. Such future costs may be one-off (such as the cost of implementing staff redundancies) or recurrent (such as the cost of additional services). To the extent the reference line is used to provide a like-for-like comparison to the costs of the new business model, I believe that the reference line should reflect any costs associated with additional services provided under the new business model that are required for reasons of prudent risk management."

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62 It is UED's view that the relevant amount must be considered as Commercial in confidence.

63 AER, Draft Decision, pages 233 and 234.

64 Philip Williams, Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery, July 2010, paragraphs 46 and 47.

Consistent with the approach suggested by Philip Williams, UED has removed from the base year those costs that are directly related to the 7/11 project, including the conceptual development of the new business model and the competitive tendering exercise. It is noted that the costs removed by UED reflect the actual costs incurred in 2009. These differ from the non-recurrent costs removed by the AER in its Draft Decision because those amounts were based on budgeted rather than actual costs, and included costs other than those relating to the 7/11 project.

UED also notes Philip Williams' clear statement regarding the transformational costs incurred by UED. In particular, Philip Williams concludes that UED should be entitled to recover any forthcoming regulatory period costs arising from the adoption of a new business model where that model leads to overall operating expenditures that reasonably reflect efficient and prudent costs. Such future costs may be one-off (such as the cost of implementing staff redundancies) or recurrent (such as the cost of additional services).

Philip Williams also explained that the AER's 'year 4' approach to estimating UED's operating expenditure should recognise that UED's new business model will deliver additional services compared to the existing OSA. In order to assess the relative efficiency and prudency of UED's existing and new business models it is appropriate to include the costs of these additional services in the AER's 'year 4' approach. This issue is discussed further in section 5.3.6 below.

5.3.2.4 Regulatory accounts transfer between capex and opex

As already noted, the AER has adopted a year 4 roll-forward approach in establishing an operating expenditure forecast for UED. A key component of this approach is the application of the costs reported in JAM's 2008 regulatory accounts[65].

The AER will be aware that JAM provides both capital and operating services to UED under the Operating Services Agreement (OSA). Each year UED processes an adjustment to its regulatory accounts to ensure consistency with the 2006 EDPR and UED's established capitalisation policy. The adjustment reclassifies, overheads, included in the capital expenditure charge levied by JAM under the OSA, as UED operating expenditure. The adjustment is detailed in the policies and the journals that underpin UED's annual regulatory accounting statements.

Most importantly, the adjustment is consistent with requirements set out by the ESC in its 2006 – 2010 and 2001 – 2005 final decisions, at which time the ESC determined that UED had over-allocated overhead expenditure to capital. Accordingly, the ESC required UED to transfer capitalised overheads back to operating expenditure. UED has been conforming with these requirements since that time.

The AER did not include this adjustment when it derived UED's base year operating expenditure estimate. Accordingly, the amount of expenditure that is the subject of the adjustment has not been included in the Draft Decision in either operating expenditure or in capital expenditure (the RAB). As explained above, it should be treated as operating expenditure. The AER has therefore erred in its approach to establishing UED's revenue requirements for the 2011 – 2016 regulatory period.

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65 The AER has indicated that for the purposes of the Final Decision it will adopt audited 2009 cost data. .

The adjustment (labelled as "variance") to UED's regulatory (capital) accounts is shown in the table below:

Table 5-9: Identification of adjustment to UED's regulatory accounts (capital)

Item	2006	2007	2008	2009
Statutory additions				
Additions – Note 14	111,015	107,631	106,331	162,804
Additions – Note 15	6,481	9,580	29,310	48,025
AIMRO stock and other[66]	0	0	0	2,486
Total Statutory additions	**117,496**	**117,211**	**135,641**	**213,315**
Regulatory Additions				
Net Additions – capex	98,428	91,878	115,074	192,880
Add back customer contributions	12,617	18,811	13,810	13,264
Total Regulatory additions	**111,045**	**110,689**	**128,884**	**206,144**
Variance	**-6,451**	**-6,522**	**-6,757**	**-7,171**

The corresponding adjustment (also labelled as "variance") to UED's regulatory O&M accounts is shown in the table below:

Table 5-10: Identification of adjustment to UED's regulatory accounts (operating)

Item	2006	2007	2008	2009
Statutory O&M				
Operating fees – Note 1	78,807	77,996	81,016	83,778
Other expenses – Note 1	13,756	15,159	16,742	23,996
Total Statutory O&M	**92,563**	**93,155**	**97,758**	**107,774**
Regulatory O&M				
Maintenance	30,850	29,808	32,613	21,685
Operating expenses	68,165	70,055	71,976	93,260
Total Regulatory additions	**99,015**	**99,863**	**104,589**	**114,945**
Variance	**+6,451**	**+6,522**	**+6,757**	**+7,171**

It is noted that the amounts labelled as "variance" in each year in the capital and O&M accounts offset one another. As noted above, these amounts represent the adjustment to UED's regulatory accounts to effect the reclassification to operating expenditure of overhead costs which are charged by JAM to UED as capital expenditure under the OSA. The re-classification of this expenditure has the effect of increasing UED's reported operating expenditure, and decreasing the capital expenditure that is rolled into the RAB by an equivalent amount.

These adjustments are explained in the accounting policies of UED's regulatory accounts and a journal transfer is also processed. For 2009, the accounting policy reference can be found on page 40 under section 1.2 and the journal transfer can be found on page 45,

[66] The AMIRO stock relates to meters purchased that have been capitalised for regulatory purposes but not for statutory purposes. UED has the meters in stock however as at 31 December 2009 had not installed them.

journal number 5. Similar explanations are found in the audited regulatory accounts of previous years for the 2006-10 regulatory period.

Adjustments of this type have been processed by UED since 2001, however for the purpose of brevity, the explanation provided in this note relates to the period from 2006 (the commencement of the current regulatory period).

It is noted that the re-classification explained above is undertaken by UED for the purpose of preparing UED regulatory accounts, and it does not affect the reporting of these costs by JAM. JAM does not make an adjustment of this nature to its own costs for regulatory reporting purposes. JAM reports costs of providing services in accordance with its particular accounting policies.

UED's re-classification the capitalised overheads charged (and reported) by JAM as capital expenditure, and transfers this amount to operating expenditure. As noted above, JAM does not undertake such an adjustment in its regulatory accounts.

In making its Draft Decision the AER has erred by not taking into account UED's reclassification of capital expenditure as operating expenditure. In particular:

- The AER has accepted UED's reported capital expenditure in rolling forward the asset base value, noting that UED's reported capital expenditure has been adjusted downwards to reflect the transfer of JAM overheads from capital to operating expenditure.

- To derive UED's base year operating expenditure, the AER has taken JAM's reported operating cost in servicing UED, which is net of all overheads capitalised.

- Under the approach applied by the AER, the capitalised overhead costs incurred by JAM in providing services to UED are excluded from both operating expenditure and capital expenditure. The exclusion of these costs is therefore in conflict with the revenue and pricing principles contained in section 7A of the National Electricity Law, which require UED to be provide with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control services.

- The correct approach would be to add back the overheads adjustment to UED's operating costs - in accordance with the cost allocation policy that has underpinned UED's regulatory accounts during the whole of the current regulatory period, and in accordance with the definition of UED's expenditure benchmarks for the current regulatory period.

UED has been provided with a letter from Ernst & Young that attests to this adjustment as being consistent with the audited regulatory accounts, the AER's Cost Allocation Guidelines and UED's Cost Allocation Method. A copy of the letter is attached. It is noted that for the purpose of preparing regulatory accounts Ernst & Young is engaged under a tripartite agreement with the AER and UED. The letter provides sound, independent verification of the adjustment.

Also attached as an Appendix UED has reconciled with the 2004 regulatory accounts to the ESC's base year costs for establishing the current regulatory allowances. This also demonstrates that the ESC has accepted this re-allocation of overheads back to opex in the current regulatory period. It also demonstrates the consistency with the cost allocation methodology and is consistent with regulatory practice.

On the basis of the information presented above and in the attached letter from Ernst & Young, the overhead reversal adjustment described above must be added back in any calculation of base operating expenditure for UED. This would ensure consistency with UED's cost allocation methodology, and reflect the actual costs that have been expensed by UED since 2006.

The principle behind the transfer of costs from capital to operating is designed to achieve a zero sum gain. That is rather than UED recovering these costs over the life of the asset they are recovered immediately in the form of an operating expense. UED has been processing this transfer since 2001 and therefore over $50m has not be included in the regulatory asset base. Based on the AER's draft decision UED will never be able to recover this amount. The AER's treatment of this cost allocation methodology "mismatch" breaches the principles in the rules that allow UED to recover efficient costs and breaches the basis of the cost allocation methodology.

5.3.2.5 Projection from 2009 regulatory accounts

In estimating UED's operating expenditure for the 2011-2015 regulatory period, the AER projects forward from UED's 2009 regulatory accounts. The approach adopted by the AER is to employ assumptions made by the ESCV in its 2006 EDPR, which was finalised in October 2005. The AER explained this adjustment in the following terms[67]:

> "The AER has rolled forward the 2009 base year costs to 2010 (the last year of the current regulatory control period) consistent with the approach proposed by Jemena, which is based on the change in costs assumed by the ESCV in determining the benchmark opex allowance for 2009 and 2010 in its 2006 EDPR. The roll forward of the actual 2009 base year costs takes into account the change in costs assumed by the ESCV in determining the 2009 and 2010 benchmark opex allowance. This is also consistent with the ESCV's approach of assuming that any cost efficiencies achieved by the Victorian DNSPs in the final year of the regulatory control period are zero."

UED notes that the AER's approach preserves assumptions and calculations made by the ESCV in its 2006 EDPR. UED does not accept that the AER's approach is consistent with the Rules. The Rules require UED to forecast its operating expenditure for the forthcoming regulatory period. It is not reasonable to forecast cost movements between 2009 and 2010 using assumptions made by the ESCV in October 2005. Any assumption made by the ESCV regarding a specific cost movement 5 years hence has practically no value in terms of accuracy.

In order to verify the appropriateness of using the ESCV's assumed cost movement for UED between 2009 and 2010, the AER should have undertaken the following two-step approach:

1. Review the validity of the ESCV's assessment in 2005 and correct any errors in the ESCV's approach; and

2. Update the ESCV's assessment to account for outturn information, including inaccuracies in the ESCV's assumptions.

UED notes that this two step process is challenging. UED has conducted an in-depth assessment of the first step, and this is described in detail below. The conclusion from this detailed review is that the ESCV's assessment contains an error and cannot be relied upon. In relation to the second step, UED notes that the ESCV's 2006 EDPR incorporated a

67 AER, Draft Decision, page 246.

significant number of assumptions, some implicit, that would be difficult to revisit now. Consequently, UED considers it impractical to undertake the second step described above. UED therefore concludes that the AER should adopt its own estimate of the change in UED's operating expenditure between 2009 and 2010.

For the purpose of establishing an appropriate base year cost in the context of the AER's 'year 4 ' approach, UED has adopted the composite scaling factor and labour rate of 1.87% per annum, the detailed components of which are explained in sections 5.3.3 and 5.3.4 below. UED contends that this approach is reasonable and should be adopted for the purposes of establishing UED's base year costs.

In the remaining discussion set out below, UED sets out its review of the ESCV's assumptions regarding UED's cost movements between 2009 and 2010. As noted above, UED has identified an error and inconsistency in the ESCV's approach. The table below shows the change in the operating expenditure allowances between 2009 and 2010 for each of the five Victorian distributors under the ESCV's determination.

Table 5-11: Change in operating expenditure allowances from 2009 to 2010 ($ million, 2004 values)

CitiPower	Powercor	Jemena	SP AusNet	UED
0.6	4.1	1.5	3.6	-0.2

The following example illustrates the way in which the change in allowance from 2009 to 2010 is applied to derive an estimate of the 2010 operating expenditure from 2009 actual expenditure. Assume that each distributor has the same total operating expenditure in 2009 of $100 million. The application of the amounts shown in the table above would result in the following estimates of 2010 operating expenditure for each distributor.

Table 5-12: Estimated 2010 expenditure

CitiPower	Powercor	Jemena	SP AusNet	UED
100.6	104.1	101.5	103.6	99.8

It is evident from the above table that the ESCV's assumed cost change between 2009 and 2010 will increase all of the distributors' 2010 estimated costs, with the exception of UED which is reduced to 99.8 from 100. This inconsistent outcome creates a suspicion that the ESCV's underlying calculation contains an error or inappropriate assumption of some kind for UED.

To explore this issue in further detail, it is important to examine the ESCV's calculation for UED's operating expenditure changes in its 2006 EDPR. The ESCV made assumptions about three matters relating to operating expenditure changes:

- A rate of change estimate in percentage terms, which combines the effects of labour and material costs and productivity improvements. In UED's case, the ESCV assumed an increase of 0.58 per cent per annum;
- A growth rate estimate in percentage terms, which takes account of increases in customer numbers and increased maintenance associated with a growing network. In UED's case, the ESCV assumed an increase of 1.78 per cent per annum; and
- Step changes in $3.6 million per annum, which reflected the assumed costs of meeting new obligations.

The table below shows the ESCV's calculations for UED for the 2006 – 2010 period, expressed in real $ million in 2004 values.

Table 5-13: UED's updated version of the AER's 'year 4' operating expenditure forecasts ($ million in 2004 values)

	YEAR ENDING 31 DECEMBER					Change 2009-2010
	2006	2007	2008	2009	2010	
Base cost	74.86	74.86	74.86	74.86	74.86	
Plus rate of change	0.44	0.88	1.32	1.77	2.22	
Plus growth	1.33	2.68	4.06	5.46	6.88	
Sub – total	**76.63**	**78.42**	**80.24**	**82.09**	**83.97**	**1.88**
Plus step	4.16	4.05	3.95	3.94	1.82	**-2.12**
Total opex	**80.79**	**82.47**	**84.19**	**86.03**	**85.79**	**0.24**

The following points are evident from the above table:

- The ESCV's sub total of costs for UED in 2010 is $83.97 million compared to $82.09 million in 2009. Therefore, the ESCV assumes a cost increase of $1.88 million between 2009 and 2010 at the sub total level.
- The ESCV's total cost for UED in 2010 is $85.79 million compared to $86.03 million in 2009. Therefore, the ESCV assumes a cost decrease of $0.24 million between 2009 and 2010, which is the figure (subject to rounding) adopted by the AER in its base year adjustment discussed above.
- Therefore the main driver for the assumed cost reduction in total opex between 2009 and 2010 is the reduction in the allowance for the costs of step changes from $3.94 million in 2009 to $1.82 million in 2010.

Given the importance of the step change assumption in taking UED from a cost increase position – consistent with the other distribution businesses – to a cost decrease position, it is useful to review the ESCV's step change assumption in its 2006 EDPR. Table 6.23 from the ESCV's Final Decision is reproduced below:

Table 5-14: ESCV Final Decision step change for each business by year ($ million in 2004 values)

	2006	2007	2008	2009	2010	Total
AGLE	2.0	1.7	1.6	1.6	1.7	8.5
Citipower	2.3	2.8	2.2	2.2	2.2	11.8
Powercor	8.4	8.5	8.3	8.4	9.0	42.5
SP Ausnet	11.6	11.4	11.3	11.0	11.0	56.4
United Energy	4.2	4.1	3.9	3.9	1.8	17.9

The above table shows that between 2009 and 2010 UED is the only business where the costs of step changes are assumed to fall. All other distribution businesses are assumed to experience either no change or an increase in step change costs between 2009 and 2010.

UED has reviewed its submissions to the ESCV and the ESCV's draft and final decisions to ascertain whether there is any reason for the particular profile of step changes adopted for UED in the ESCV's Final Decision. Our review has indicated that there is no explanation for the reduction in step changes. Furthermore, the ESCV's Draft Decision shows a flat profile for UED's step changes as set out in Table D.87 (reproduced below)[68].

Table D.87: Operating and maintenance expenditure, United Energy, $million, real $2004

	Recurrent opex	Forecast opex					
	2004	2005	2006	2007	2008	2009	2010
Base opex	84.3	82.5	82.5	82.5	82.5	82.5	82.5
Rate of change	—	—	0.0	0.0	0.0	0.0	0.0
Impact of growth	—	—	0.0	0.0	0.0	0.0	0.0
Step changes	—	—	2.8	2.8	2.8	2.8	2.8
Total opex			85.4	85.4	85.4	85.4	85.4

UED's submission in response to the Draft Decision argued for an increase in the regulatory allowance for step changes. However, UED's submission did not argue that the ESCV's flat profile for step changes in its Draft Decision should be altered. In responding to the ESCV's Draft Decision, UED concluded that the annual allowance for step changes should be increased[69]:

> "This submission has substantiated scope changes costing $6 million per annum, which should be incorporated into the expenditure benchmarks for the 2006-10 regulatory period."

It is worth highlighting the following points in relation to the ESCV's Draft Decision and Final Decision in relation to step changes:

- The ESCV's Draft Decision initially provided UED with a step change allowance totalling $14 million or $2.8 million per annum for each of the 5 years; and

- Following UED's submission to the ESCV's Draft Decision, the ESCV increased the total step change allowance from $14 million to $17.7 million. However, the allowance for 2010 decreased from $2.8 million to $1.8 million from the ESCV's Draft Decision to its Final Decision. There is no explanation in the Final Decision as to why the ESCV would increase UED's step change allowance over the 5 year period, but reduce it by $1 million in 2010.

UED contacted the ESCV repeatedly over a number of weeks in June and July this year, requesting details of the reasons for the step change allowance adopted in the ESCV's Final Decision. The ESCV has declined to provide any information. UED has made a Freedom of Information Request to the ESCV and will forward the outcome to the AER as soon as it is received.

[68] Essential Services Commission, Draft Decision, Part D Summary of Draft Decision by distributor United Energy, June 2005, page 14.

[69] UED, Submission to the Essential Services Commission, Operating and Maintenance Expenditure, August 2005, page 18.

In light of the evidence provided above, UED believes that it is reasonable to draw the following conclusions:

- The ESCV's profile for step change cost allowance is markedly different for UED compared to the other distribution businesses;
- The ESCV's profile for UED's step change cost allowance changed between the Draft Decision and the Final Decision, and there is no explanation for the change from the ESCV's Final Decision or UED's submission in response to the Draft Decision;
- If the AER maintains the ESCV's profile assumption for UED its effect will be to impose a decrease in UED's base year costs compared to 2009, whereas all other distributors will be allowed an increase in their base costs. UED believes that such an outcome would be biased and unreasonable because it would rely on an error or unreasonable assumption in the ESCV's Final Decision; and
- It is appropriate for the AER to make an adjustment to the ESCV's profile of step changes for the purposes of forecasting UED's operating expenditure. .The operation of the ESCV's efficiency carryover mechanism is separate to the task of deriving an estimate of UED's future operating expenditure requirements.

To correct the ESCV's calculation UED's step change cost allowance of $17.7 million over the 2006-2010 regulatory period should be averaged to provide a constant allowance of $3.58 million per annum. This approach achieves a zero cost change with respect to step changes between 2009 and 2010, an assumption which is consistent with the outcome for CitiPower and SP AusNet, and less favourable to UED than the rising cost profile assumed for Jemena and Powercor.

The table below updates Table 6.23 from the ESCV's Final Decision, showing the revised step change cost profile proposed by UED.

Table 5-15: Updated version of the ESCV's operating expenditure profile for UED ($ million in 2004 values)

	YEAR ENDING 31 DECEMBER					Change 2009-2010
	2006	2007	2008	2009	2010	
Base cost	74.86	74.86	74.86	74.86	74.86	
Plus rate of change	0.44	0.88	1.32	1.77	2.22	
Plus growth	1.33	2.68	4.06	5.46	6.88	
Sub – total	**76.63**	**78.42**	**80.24**	**82.09**	**83.97**	**1.88**
Plus step	3.58	3.58	3.58	3.58	3.58	**0.00**
Total opex	**80.21**	**82.00**	**83.28**	**85.67**	**87.55**	**1.88**

The above calculation shows that correcting the ESCV's approach would result in a cost change between 2009 and 2010 should be an increase of $1.88 million, rather than a reduction of $0.2 million as per the AER's Draft Decision. This increase compared with an average increase for the other four distributors of $2.45 million.

UED reiterates its view that it is incumbent on the AER to ensure that its estimate of cost changes between 2009 and 2010 is reasonable. UED's analysis of the ESCV's assumptions demonstrates that there is sufficient uncertainty regarding UED's data for these assumptions to be set aside. Furthermore, the ESCV's assumptions are out-of-date and do not reflect the best available information.

For the purposes of establishing an appropriate base year cost, UED has adopted the combined scaling factor and labour rate of 1.87% per annum as submitted in this Revised Regulatory Proposal. UED contends that this approach is reasonable and should be adopted for the purposes of establishing UED's base year costs.

5.3.2.6 Margin on cost of outsourced services

The AER's year 4 approach does not include any profit margin for the provision by JAM of network services under the OSA. Philip Williams of Frontier Economics has provided an independent expert opinion, in which he makes the following comments on this issue[70]:

> "However, the AER's approach implicitly assumes that UED would be able to secure appropriate servicing of its network over the next regulatory control period at prices similar to the costs JAM incurred over the period of the OSA. This may not be the case for several reasons.
>
> First, to the extent that the current OSA has led to incentives for JAM to under-service UED's network, it may be both efficient and prudent for UED to increase the scope or scale of the services provided under a renegotiated outsourcing arrangement. Such an increase in scope or scale would help ensure that UED was less likely to breach its mandatory service standards as a result of JAM's cost-cutting. Any increase in scope or scale under a revised OSA is likely to come at increased cost.
>
> Second, as the provider of an unregulated service and as an entity with only some common ownership with UED, JAM will need to recover at least its costs of entering into its contract with UED. These costs will include the cost of any funds required to finance activities to be undertaken under the contract. If JAM cannot receive such a price, it will not enter into a new contract with UED. However, under the AER's "two-stage approach" to outsourcing and related party transactions, UED may not be able to recover operating expenditure in excess of a related party's costs. Given these constraints, UED may not be able to come to a new agreement with JAM for the 2011-2015 regulatory control period.
>
> In light of these considerations, I consider that it would be not be prudent for UED to assume that the current JAM contract could be renewed and the current business model will be extended over the regulatory period, especially if JAM is losing money through the current contractual arrangements. This is relevant under part (2) of Rule 6.5.6(c)."

UED is well aware that the regulatory treatment of profit margins for services provided by related parties is a contentious issue. In fact, as explained in UED's original Regulatory Proposal, the regulatory issues regarding related party contracts is one reason why UED has decided to adopt a new business model based on competitively tendered outsourced service providers. Nevertheless, if the AER is to develop a realistic 'year 4' approach, UED considers it appropriate to include a profit margin as a percentage of JAM's outsourced costs.

UED notes that the AER's decision on Jemena's Gas Networks in NSW commented that benchmarks indicate that profit margins extend from around 3 per cent to more than 12 per

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70 Philip Williams, Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery, July 2010, paragraphs 62 and 65.

cent[71]. Assuming a margin for JAM towards the low end of this range a margin of 6 per cent on JAM's 2009 costs would be reasonable. UED has therefore included a 6 per cent addition to the base year costs. A report prepared by Ferrier Hodgson is attached as an appendix to demonstrate that 6 per cent is a reasonable margin. This information was used by UED in relation to its AMI submission.

A further issue raised by Philip Williams is the possibility that JAM is under-servicing UED's network to a point where existing cost levels are not sustainable. As noted in information submitted by UED with its original Regulatory Proposal, the possibility of cost-cutting by JAM to unsustainable levels is a matter that has been considered by UED's Board, and was also a consideration in adopting the new business model. Evidently, the future provision of services under the OSA would need to be provided at sustainable cost levels, and cost projections should reflect this operational requirement. For the purposes of amending the AER's 'year 4' approach, however, UED has not included a specific allowance to address this issue.

5.3.2.7 Escalation of 2009 cost data to 2010

The AER's base year cost approach applies an adjustment to express the 2009 base year costs in 2010 price levels. A standard approach for expressing 2009 costs in 2010 price levels is to apply an estimate of the change in the CPI from 2009 to 2010. In contrast to this standard approach, the AER has adjusted the base year for historic inflation, rather than forecast inflation. There is no sound reason to adopt historic CPI data in preference to forecast data. UED has therefore amended the base year cost to the reflect forecast increase in CPI of 2.57 per cent instead of the AER's figure of 1.26 per cent. The 2.57 per cent is consistent ith the AER's assumptions used for the cost of capital.

5.3.3 Net growth rate (scale) escalators

UED did not apply a scale escalation factor in the development of its operating expenditure forecast. As explained in section 5.2.2 of this Revised Regulatory Proposal, the tender process for outsourced services addressed unit prices and volumes concurrently. The "price" offered by each tenderer was in the form of an operating expenditure budget that reflected the product of unit prices and forecast volumes, and UED and bidders faced strong incentives to ensure that bids were based on the best possible information regarding unit prices and expected work volumes.

The AER has set aside UED's operating expenditure forecast and has instead relied on rolling forward UED's year 4 cost and adding on costs for scale escalation.

In its Draft Decision the AER bases its scale escalator on:

- A composite network growth factor calculated as a simple average of the annual growth in line length and the number of distribution transformers and zone substations over the forthcoming regulatory control period; and
- The annual growth in customer numbers over the forthcoming regulatory control period.

The AER then adjusts the scale escalator for an "opex/capex trade off".

71 AER Final Decision, Access arrangement proposal for the NSW gas networks, Jemena Gas Networks, June 2010, page 270

The AER also noted that it has not received any information from UED regarding distribution transformers and has used line length as a proxy until it receives the necessary information. The AER has invited businesses to propose installed zone substation capacity in lieu of growth in the number of zone substations as an input to the composite network growth factor.

UED notes that the approach adopted by the AER in its Draft Decision for the Victorian distributors is inconsistent with the approach adopted by it in the ETSA Utilities Final Decision just one month earlier. By contrast in the NSW electricity distribution review the AER undertook a "high level assessment of reasonableness" of peak demand forecasts. Page 93 of the NSW Final Determination included the following commentary:

> "The AER notes that while Country Energy and EnergyAustralia's revised regulatory proposals state that they have developed revised maximum demand forecasts, these forecasts were prepared on a global (top–down) basis, and do not incorporate spatial forecasts at the zone substation level. While global forecasts are useful as a check on spatial forecasts and to indicate general trends on the networks, spatial forecasts are required to assess necessary expenditure on the network. As there was insufficient time for the DNSPs to prepare revised spatial maximum demand forecasts, the AER's assessment of the revised global maximum demand forecasts and the impacts on load driven capex are limited to a high–level assessment of reasonableness."

In the ETSA Utilities Final Decision, the AER agreed with ETSA that substation capacity is a better measure than the number of zone substations. The AER also noted on page 121 of the ETSA Final Decision:

> "The AER considers the use of a weighted average will provide a stronger reflection of the proportion of future opex requirements compared with assuming equal weighting across the three asset classes."

It is unclear why the AER adopted a simple average in Victoria yet applied a weighted average in the ETSA decision and did nothing at all similar in the NSW decision.

It is UED's view that neither the AER nor its consultant has sufficient technical knowledge of UED's assets to competently make decisions at this level of detail. Nor does the regulatory framework either anticipate or require the AER to delve into the operation of UED's network at such a detailed level. There is no requirement for the AER to take such an approach under the Rules and application of a "high level assessment of reasonableness" would be more than adequate for the AER to discharge its obligations under the Rules.

Despite this reservation, the table below lists the number of network drivers in UED's territory for the forthcoming regulatory control period.

Table 5-16: Characteristics of UED's network

	2010	2011	2012	2013	2014	2015
Line length	12,833	12,957	13,081	13,205	13,329	13,510
Distribution transformers	12,234	12,600	12,941	13,285	13,629	13,976
Zone sub (MVA)	3,050	3,089	3,161	3,260	3,326	3,359
Customer numbers	624,480	630,635	636,421	641,506	646,067	650,752

Consistent with the AER's decision for ETSA UED adopts the following parameters for scale escalation.

The AER's consideration of the capex/opex trade-off is a legitimate feature of its model. It reflects the fact that when assets are replaced, the new assets will not require the same level of maintenance in the short term as the old assets, and therefore some opex savings arise. However, this approach needs to also take into account an offset to reflect the increasing number of aging assets that are not replaced and which therefore require increasing maintenance expenditure. It is noted that the AER's approach fails to recognise:

- the aging of the asset base, and
- the increasing number of assets that are aging,

compared to the current trend line of expenditure.

In addition to the above, UED notes that the model provided by the AER is complicated and does not reflect the numbers contained in the Draft Decision. For example the AER does not apply the correct replacement forecast in its model; it adopts UED's forecast rather than the 50 per cent lower allowance determined in the Draft Decision. This results in the AER's estimate of the effect of the capex/opex trade-off being biased towards providing a lower scale escalation factor and therefore a lower operating expenditure allowance.

In addition, the AER's model makes no attempt to consider the impact of additional maintenance as younger assets enter a phase of increasing maintenance requirements. Under the AER's Draft Decision for replacement capital expenditure this number becomes significant. Based on UED's forecast of replacement capital expenditure (of approximately $280 million over five years) UED's predicted average asset age increases.

Under either replacement capital expenditure scenario, there will be an increase in the average age of UED's assets. The AER has not considered the impact of an aging asset base on the capex/opex trade-off component of its scale escalation factor. In the absence of robust analysis that would justify a reduction in the scale escalation factor to reflect the capex/opex trade-off, UED suggests this adjustment be set to zero.

Applying the AER's approach to scale escalation, and adopting the correct input data, the correct calculation of the scale escalation factor is set out in the table below.

Table 5-17: Calculation of scale factor for UED

Element	Scale factor for this element
Line length	0.83%
Distribution Transformers	2.70%
ZS transformers	1.09%
Customer Numbers	0.83%
Capital trade off	0.0%

Based on the data presented above, UED has adopted a net growth rate escalator of 0.77 percent per annum.

5.3.4 Real cost escalators (labour)

For the purpose of preparing the forecast of in-house operating expenditure UED engaged BIS Shrapnel to forecast the real level of wage growth for the 2011 – 2015 period. Based on BIS Shrapnel's advice, UED's original Regulatory Proposal adopted a real average labour escalation rate of 2.60 per cent per annum. The 2.60 per cent forecast is for average weekly ordinary time earnings (AWOTE). UED applied this escalation rate to internal labour only, noting that a significant proportion of its operating expenditure forecast was based on tendered prices.

In its Draft Decision the AER criticised UED's approach in adopting the AWOTE wages measure. The Draft Decision argued that the labour price index (LPI) is a superior measure that it had adopted in previous reviews (citing its NSW final decision as an example). The AER also engaged Access Economics to prepare a forecast of wage growth. The AER has accepted the Access Economics' forecast over BIS Shrapnel, and applied LPI instead of AWOTE.

UED (in conjunction with SP AusNet and Jemena) engaged BIS Shrapnel to prepare an updated forecast of labour costs, and to critique the methodology adopted by Access Economics. The reports prepared by BIS Shrapnel are attached as appendicies to this submission.

The critique prepared by BIS Shrapnel concludes as follows:

> "We have demonstrated that AE [Access Economics] wage deviation model is seriously flawed. It fails to incorporate the underlying structural drivers of wage formation in the EGW [electricity, gas and water] sector. Moreover, the model's component determinants do a poor job in explaining the variations in the sector wage deviations. As a result, the prescribed model is far from a reasonable approximation to the underlying data generating process.
>
> AE wage deviation model plays an integral part in AE overall sector wage forecasts. Given the limitations of the wage deviation model, we believe AE final EGW wage escalation forecasts are seriously undermined. As a result, the forecasts provided by AE cannot be considered as optimal. In this regard, they should be rejected by the AER."

As noted above, the AER has also adopted LPI on the basis that this is consistent with previous AER decisions, citing the NSW final decision as one such example (see footnote 76 of Appendix K of the Draft Decision). In that decision the AER adopted Econtech's updated NSW EGW wage growth forecast. Importantly page 489 of that decision notes that Econtech states that the forecasts reflect the following factors:

- an enhanced approach to labour cost forecasting, which was initially used in the September 2008 report
- national accounts data up to December 2008 (published by the Australian Bureau of Statistics (ABS))
- average weekly earnings data up to November 2008 (obtained by request from the ABS)
- the Federal Government stimulus package announced in December 2008 and February 2009.

It is noteworthy that in its advice to the AER on the NSW decision, Econtech adopted AWOTE rather than LPI as the basis for its labour forecasts. This is in direct contradiction of the AER's Victorian Draft Decision and is inconsistent with some of the reasoning advanced by the AER for its adoption of LPI. It is also noted the AER accepted AWOTE in its recent Final Decision for Jemena Gas Networks.

For the purpose of preparing this Revised Regulatory Proposal, UED has again engaged BIS Shrapnel to advise on labour cost escalators. The BIS Shrapnel report is attached as to this submission. UED is adopting the AWOTE forecast contained in that report, which is an average of 2.2 per cent over the forecast period. For modelling purposes UED has adopted the profile recommended by BIS Shrapnel. As already noted, UED has applied this rate to derive internal labour cost forecasts that form part of the operating expenditure forecast.

5.3.5 Scope changes

The AER has rejected a number of UED's proposed scope changes. In relation to those activities where the AER has accepted that a scope change exists, the AER has not accepted the operating expenditure forecast provided by UED and has instead adopted an alternative forecast in the Draft Decision.

The AER's approach to assessing scope changes in the Victorian Draft Decision differs to that applied in its other recent decisions. For instance, in its April 2009 NSW electricity distribution review Final Decision the AER allowed step changes on the basis of criteria other than whether those step changes are attributable to a changed regulatory obligation. In the NSW Final Decision, the AER relied on criteria set out by its consultants (Wilson Cook), who stated that for a step change to be accepted, the business should demonstrate that:

(a) it is related to a fundamental change in the business environment arising from outside factors or offset by cost efficiencies in other areas;

(b) it is attributable to the imposition of new or changed obligations due to external factors including, if relevant, mandated improvements in service levels;

(c) it is of a type that will improve service levels voluntarily as opposed to being mandated - in respect of which customers' willingness-to-pay for the improved service should be demonstrated;

(d) it will bring cost savings or benefits to customers - in respect of which, the business should be able to demonstrate that:

    (i) it is continually looking for better ways of using its resources and improving its processes and systems to improve service levels or achieve cost efficiencies;

    (ii) it has defined the savings and benefits in terms of their nature and the expected time of their realisation; and

    (iii) where the savings and benefits are quantifiable, they have been quantified in sufficient detail for cost-benefit analyses to be prepared and that the cost-benefit analyses justify the investment; or

(e) alternatively, if it does not meet any of these criteria, the business has demonstrated that it will continue to operate efficiently as a whole, despite the cost increase.

UED considers the criteria adopted by the AER in relation to the NSW distributors to be reasonable, and should be applied in relation to UED's proposed scope changes.

The table below shows a comparison of the scope change amounts contained in UED's original Regulatory Proposal and those provided in the Draft Decision. The amounts adopted for the purpose of UED's Revised Regulatory Proposal are also shown.

A separate attachment sets out detailed information to substantiate the additional costs associated with Vegetation Management due to Electric Line Clearance Regulations 2010.

Table 5-18: Scope changes (shown in $'000 in 2010 dollars)

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
Customer and Market Management				
Customer charter	1,000	735	1,000	The AER has proposed a lower amount for this activity than that proposed by UED. From the information provided in the Draft Decision it is not possible to determine the basis of the exact adjustment made, however the AER has removed glow in the dark magnets proposed by UED. The AER claims that these items are in excess of what is required to meet UED's relevant obligations. (It is noted that UED did not include expenditure forecast of $265,000 for glow in the dark magnets in the original Regulatory Proposal). UED does not accept the AER's proposition and notes that initiatives such as these are important in order to provide a vital service. During times where there is no power or light it is difficult for customers to find their charter, log onto a website or find their bill so they can contact UED's call centre. Initiatives such as these can be useful aids for customers in times of stress. Customer communications is an important activity for UED. If communications are not clear higher costs such as increased calls to UED's call centre, increased customer complaints and regulatory enquiries will be incurred. Expenditure on targeted communications is prudent and efficient and ultimately benefits customers
Additional marketing	400	0	400	UED's current marketing costs are very low compared to other businesses. UED has not included this role in the scope of outsourced activities; nor is it included in UED's forecast of in-house costs. UED needs to increase its role in the community to a level similar to other distribution businesses base costs. The costs of this activity include those associated with customer liaison, engagement with other stakeholder groups and the provision of better information to those groups on various matters such as solar, tariffs, the customer charter etc.

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discussson
Extreme event management	400	0	400	In its original Regulatory Proposal, UED explained that this activity was not included as part of the scope outsourced services. These activities would be required to be performed internally and the estimated cost was for 0.5 of an FTE plus other incidental costs. The AER claimed that UED had not demonstrated that it had effectively engaged with key stakeholders to achieve the efficient cost associated with this initiative. In response to this UED points the AER to UED's engagement with the ESC on the relevant consultation phase. In particular, the AER should also note the ESC press release dated 24 February 2010, which states: "The Minister was concerned to ensure that, in the event of significant and widespread energy supply events, the community can be assured that: • the communication of supply outage details are coordinated for consumers and the media • support agencies are able to assist customers with special needs in the event that these customers are off supply for more than 24 hours • there are improvements in regard to outage notifications to customers and options for better handling faults reported by customers • call centres perform to high standards during these events." This step change was proposed in order to address the Minister's concerns and stakeholders' concerns that were expressed in the ESC's review, and the change to the regulatory obligation. It is noteworthy that this new obligation is essentially in two parts. These are: to communicate more effectively in extreme events (this scope change); and to communicate with customers annually to provide more detailed information (being a new regulatory obligation, the costs of which are described below in the scope change tilted Customer Communication")

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
Total Customer and Market Management	1,800	**735**	**1,800**	
Network Operating				
Changes to bushfire risk management given increased impacts of fire starts due to drought and climate change	2405	0	2405	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected this UED's proposal on the basis that the step change does not represent a new or changed regulatory obligation. UED does not dispute the current status of the regulatory obligations, however UED points out that there does not need to be a change in rules to drive a change in interpretation, or a change in the expectations of community and government. This step change meets criterion (a) of the criteria applied by the AER in its NSW Final Decision. Under that Final Decision, the AER accepted as a step change an increase in expenditure that is "related to a fundamental change in the business environment arising from outside factors". Accordingly, the AER should recognise the increased risk of bushfire starts associated with drought and climate change, and the Final Decision should provide the additional operating expenditure sought by UED to ensure that the company is positioned to mange this risk efficiently and effectively. UED notes that other DNSPs have received an expenditure allowance for these activities.
Climate change studies	438	0	438	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected this UED proposal on the basis that the step change does not represent a new or changed regulatory obligation. This step change meets criterion (a) of the criteria applied by the AER in its NSW Final Decision (namely that the increase in expenditure is "related to a fundamental change in the business environment arising from outside factors"). The proposed climate change studies will provide information to the company to ensure that operating and capital expenditure is deployed as efficiently as possible to address

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
				and mitigate the impacts of climate change. UED notes that other DNSPs have received an expenditure allowance for these activities.
Compliance to New Safety Management System	1,625	0	1625	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast tendered forecast. The AER has rejected this approach on the basis that it does not represent a new or changed regulatory obligation. UED notes that other DNSPs have received an expenditure allowance for these activities.
Line clearances	0	1,387	42,700	UED originally proposed to include this new obligation as a pass through event. Since UED lodged its original Regulatory Proposal, the legislation giving effect to new line clearance standards has passed and there is more certainty in the ability to forecast these costs. UED is liaising with the ESV in order to provide further clarity on these cost estimates, particularly in light of the RIS that the AER has adopted as the basis for proving a forecast for this new activity. In accordance with the AER's instructions UED has now included a revised operating expenditure forecast as a step change. A separate appendix is attached that provides further details regarding the activities of this new step change
Extra Audit for ESMS – Operations	100	0	100	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER has rejected this approach on the basis that it does not represent a new or changed regulatory obligation. This activity forms an integral part of UED's ESMS implementation, and the

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
				company should be provided with an allowance for the expenditure it requires. UED notes that other DNSPs have received an expenditure allowance for this activity.
ZSS secondary spares maintenance	10	0	10	See appendix B-7 of UED's original Regulatory Proposal
Leveraging AMI technology to improve network operational management	1,400	0	1,400	UED proposed this expenditure step change in order to maximise the benefits of the AMI program. The activities proposed are not included in schedule 2.1 of the OIC and have therefore not been funded by the metering charges. Benefits have not been calculated for this program on the basis that they are not yet known. In addition some of the future benefits may be in the form of customer benefits that are not cost savings to UED – this is no longer achievable under the AER's approach. Some of the benefits may also be accrued in the next regulatory period. UED is committed to the AMI program and committed to passing benefits onto consumers. In order for benefits to accrue UED requires this regulatory allowance in the five year period before proceeding on projects that have longer pay back periods. These benefits include the ability to achieve faster restoration times following faults, increased capability to manage the network more dynamically and the ability to implement different engineering solutions based on AMI data.
Insurance premium increase	3,530	3,530	3,530	UED accepts the AER's Draft Decision in this Revised Regulatory Proposal.
Total Network Operating	9,508	**4,917**	**52,208**	
Emergency Management				

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
Supply restoration costs due to increased frequency and severity, e.g. weather extremes (climate change)	6,500	**0**	**6,500**	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected UED's proposal on the basis that it does not represent a new or changed regulatory obligation. UED has provided additional information in the RQM section of this response that details the additional faults incurred due to asset failure. The AER has not funded the replacement program, arguably necessitating an increase in this estimate. Based on UED's capital forecast this amount is necessary in order to address the increasing asset failures. UED notes that the Draft Decision provide other DNSPs with an expenditure allowance for this activity.
Routine Maintenance				
More frequent POEL inspection cycle	272	0	272	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected UED's proposal on the basis that the activity does not represent a new or changed regulatory obligation. As a prudent measure UED plans to increase the frequency of POEL inspection, and the company should be provided with an operating expenditure to enable it to implement its plans. It is noted that other DNSPs have received operating expenditure allowances for such activities.

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
Zone substation power quality metering equipment maintenance	85	0	85	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected tUED's proposal on the basis that the activity does not represent a new or changed regulatory obligation. UED plans to undertake this work, and the company should be provided with an operating expenditure to enable it to implement its plans. It is noted that other DNSPs have received operating expenditure allowances for such activities.
Consultant studies on Waste Management	200	0	200	UED proposed a step change for this activity on the basis that it was not included in the the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected UED's proposal on the basis that the activity does not represent a new or changed regulatory obligation. UED plans to undertake this work, and the company should be provided with an operating expenditure to enable it to implement its plans. It is noted that other DNSPs have received operating expenditure allowances for such activities.
Increased earth testing in non-CMEN areas due to changing ground conditions caused by prolonged drought	2,500	0	2,500	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected UED's proposal on the basis that the activity does not represent a new or changed regulatory obligation. UED plans to undertake this work, and the company should be provided with an operating expenditure to enable it to implement its plans. It is noted that other DNSPs have received operating expenditure allowances for such activities
Rectify increasing rate of steady-state voltage violations	990	0	990	UED's approach to voltage variations is based on a reactive approach as the company is advised by customers. UED has previously made the AER aware of this. UED's approach is the most cost-effective approach as the cost of installing equipment to facilitate a proactive approach in this area is very high based on current technology. The University of Wollongong research quoted by the AER is not based on the

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
				identification of actual customer numbers – it is based on an estimate of the total voltage variations. AMI meters will now provide UED with empirical evidence of voltage variations. With the receipt of this information UED can no longer take a reactive approach and must now be proactive and address the voltage variations as they become known. To do otherwise would be a potential breach of its licence.
Crime stopper logo license	75	0	75	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER rejected UED's proposal and has not provided an expenditure allowance for this activity on the basis that it should be self funding and it does not represent a new or changed regulatory obligation. This activity is expected to increase security at UED premises, and reduce theft.
Static guard/patrol	110	0	110	UED proposed a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. . UED requires the expenditure allowance it is seeking in order to undertake this activity. It is noted that other DNSPs have received operating expenditure allowances for such activities.
Total Routine Maintenance	4,232	**0**	**4,232**	
Billing and Revenue				
Premium feed in tariff	900	**0**	**900**	UED has a legal obligation to pay the PFIT rebate and a legal obligation to administer the system. These obligations arise under relevant Victorian law. Under these circumstances faced by UED it does not seem unreasonable for UED to be able to recover these costs. This step change represents an increase in UED's legal obligations under its distribution licence. The company should be provided with an expenditure

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
				allowance in relation to the costs of these activities.
Regulatory				
NGERS reporting	225	0	225	UED proposed a a step change for this activity on the basis that it was not included in the scope of outsourced work that was tendered, nor was it included in UED's in-house expenditure forecast. The AER has rejected UED's proposal on the basis that this activity does not represent a new or changed regulatory obligation. UED is required to undertake this activity and it must be provided with an expenditure allowance in relation to this activity. It is noted that other DNSPs have received operating expenditure allowances for such activities
Customer communication	3,250	1,600	3,250	The AER provided a reduced expenditure allowance on the basis of the AER's assessment that UED expenditure forecast included an SMS component in the total amount. The AER's assessment was incorrect as it was based onl information provided by Jemena. UED's expenditure forecast for customer communication did not include an allowance.for the cost of SMS communications. UED currently has a customer base of 630,000. A total of $625,000 is is estimated to be required to produce and distribute the UED communications pack to all customers each year. This equates to approximately $1 per pack, assuming that a bulk print of 630,000 packs is undertaken. In addition to this cost, a further $25,000 is estimated for the publication of community advertisements, with similar content, in at least 2 major newspapers (The Age and Herald Sun). UED's forecast expenditure for customer communications covers only the cost of the annual mail-out of information as required under this new ESC requirement. SMS alerts are included in the Extreme Event management scope change, not in this scope change. The AER's allowance does not even pay for mailing costs let alone the production and advertising costs.

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
RIT-D requirements	1,785	1,390	1,390	During the course of providing the AER additional information prior to the release of the Draft Decision UED amended its forecast to reflect the AEMC's final decision. This amount was accepted by the AER's Draft Decision and is iincluded in UED's Revised Regulatory Proposal.
Regulatory reset costs	0	2,228	0	UED accepts this amount in its Revised Regulatory Proposal. It should be noted, however, that in applying it's 'year 4 roll-forward' method. the AER incorrectly removed these costs from the base year costs. The AER has rolled forward a budget for its year 4 calculations and removed an actual cost. The budget for this item was lower than the actual costs incurred.
Additional communication due to tariff reassignment	0	0	516	This new step change arises from the AER's Draft Decision. The monitoring framework proposed replaces the ESCV's current annual reporting framework for monitoring. Furthermore the AER acknowledges that the DNSPs will be required to monitor certain outcomes that they are not required to monitor under the current framework. This estimate reflects the incremental costs of additional monitoring measures that UED considers the company will be required to undertake, and which it was not required to undertake the ESCV's framework.
Annual compliance reporting				This new step change arises from the AER's Draft Decision. The AER's proposed reassignment requirements are more onerous than current obligations. In UED's view this step change (initiated by the AER) is onerous and may have been unintended. A relatively simple change to the drafting would alleviate this step change.
Total Regulatory	5,260	**5,218**	**5,381**	
Vegetation Management due to Electric Line Clearance Regulations 2010				

Step Change	Original Proposal	Draft Decision	Revised Proposal	Discusson
Demand management initiatives	10,000	**0**	**10,000**	Refer to chapter 18 for a detailed explanation of this activity.
Total scope change costs	38,200	**10,870**	**81,021**	

5.3.6 Additional services from the new business model

As explained in section 5.3.2.3, a like-for-like comparison between costs of the new business model and the costs of the existing arrangements (estimated through a year 4 roll-forward model) requires an allowance to be made for the additional services that the new business model will provide.

Section 5.3.1 shows the derivation of the base year costs and the rolled forward operating expenditure for the forthcoming regulatory period, using the AER's 'year 4' method with correct data inputs. That analysis shows that before including an allowance in the year 4 roll-forward model for the costs of additional services to be provided under the new business model, the forecast costs of the new business model are less than the estimate provided by a correctly constructed 'year 4' roll forward approach. It is therefore not necessary to include an explicit additional allowance in the year 4 roll-forward calculations to reflect the additional services that will be delivered under the new business model.

5.3.7 Self insurance

The Draft Decision explained that the AER has examined whether or not the proposed self insurance event is already compensated for through any other aspect of the regulatory regime, including through:

- other components of the operating expenditure forecast (for example, through recurrent expenditure that is incurred during the base year);
- the capex forecast or roll-forward of the RAB at the end of the regulatory control period;
- the weighted average cost of capital (WACC);
- pass through events; and
- whether any remaining negative risks (not already compensated) are outweighed by upside risks (that is, risks are negatively asymmetric in aggregate).

Appendix M of the Draft Decision provides a more detailed conceptual framework for considering whether a self insurance amount should be accepted by the AER. UED notes that the AER has accepted its view that self insurance should include risks that are controllable as well as uncontrollable. In particular, the AER concludes[72]:

> "On further consideration, the AER considers there may be merit in SP AusNet and United Energy's arguments that controllable risks should be included within the self insurance allowance (subject to where there are negative asymmetric risks in aggregate). The AER agrees that providing compensation for controllable risks through an ex ante self insurance allowance (typically based on the expected probability and cost of the event) may incentivise the DNSP to mitigate the probability and cost impact of the event in order to maximise its profitability. Accordingly, the AER considers that SP AusNet and United Energy's view that

[72] AER, Draft Decision, Appendices, page 251.

self insurance provides an incentive for the service provider to manage and control the risk is a reasonable point."

UED welcomes the AER's acceptance of UED's views regarding controllable risks. UED concurs with the AER's view that allowing a DNSP to self-insure controllable risks will provide the DNSP with an incentive to manage risk. Ultimately, all parties will benefit if the risks of controllable events can be better managed.

In applying its conceptual framework, the AER reached the conclusions set out in Table 24 of the Draft Decision (reproduced below) regarding UED's proposed self-insurance costs.

Table 7.24 United Energy's self insurance allowances for 2011–15 regulatory control period ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability —general	0.535	–
Liability—fire	0.245	–
Liability—asbestos	0.120	0.12
Poles and wires	2.710	–
Fraud	0.015	–
Insurer's default	0.125	–
Property	13.750	–
Contaminated land	2.380	–
Environmental	0.220	–
Total	**20.030**	**0.12[a]**

(a) An allowance of $24 000 per year of the regulatory period.

UED does not accept the AER's findings in relation to its proposed self-insurance costs. UED notes that in relation to a number of these self insurance items, including fraud, the AER concludes that[73]:

> "The AER further notes that if these costs are not recovered through other areas of the regulatory regime, they would be rejected on the basis that they are relatively small and would be likely outweighed by the upside risks faced by the DNSPs."

UED notes that there is no reasonable basis for the AER to conclude that there is any upside risk associated with fraud. Fraud is evidently symmetrical because there is no possibility of fraud reducing UED's costs. In addition, UED does not accept that proposed allowances for self-insurance should be rejected on the grounds that the costs are

73 AER, Draft Decision, Appendices, page 262.

"relatively small". UED's Regulatory Proposal included self-insurance items that total approximately $20 million over the forthcoming regulatory period. UED does not regard this amount as small. In any event, the Rules and the National Electricity Law do not allow the AER to reject cost forecasts on the grounds that the forecast amount is relatively small. In fact, the revenue and pricing principles set out in section 7A of the National Electricity Law require that the DNSP must be provided with a reasonable opportunity to at least recover its efficient costs.

It is also implicit in the reasoning presented in the Draft Decision that the AER would reject the proposed self-insurance amounts on the grounds of immateriality and symmetry even if UED provided further information to support its original Regulatory Proposal. This approach is particularly disappointing, and UED believes that the AER should reconsider its decision and reasoning in relation to this issue. UED would be pleased to provide further substantiation to the AER to justify UED's self insurance costs if the AER indicates a willingness to consider the submission on its merits. UED will make a further submission to the AER in relation to this issue. For the purposes of this Revised Regulatory Proposal, however, UED stands by its original submission.

5.3.8 Debt Raising Costs

The Draft Decision concludes that an allowance of 9.3 basis points per annum for direct debt raising costs is a reasonable benchmark for UED. It is noted that this allowance is less than that proposed by UED in its original Regulatory Proposal.

UED does not accept the Draft Decision allowance for debt raising costs. UED has adopted the allowance for debt raising costs shown in the PTRM accompanying this Revised Revenue Proposal. UED expects to lodge a submission to provide further information to substantiate its debt raising cost allowance.

5.4 Overall conclusions and revised operating expenditure forecasts

UED is concerned that the AER has erred in its Draft Decision by rejecting UED's operating expenditure forecasts and instead imposed substantial reductions of 23 per cent compared to UED's forecasts. If carried through to the Final Determination, reductions of this magnitude would severely constrain UED's ability to ensure its assets could be adequately operated and maintained; as would UED's ability to deliver services at standards that customers might reasonably expect.

UED does not accept that the AER's Draft Decision is consistent with the requirements of the Rules, especially given UED's exemplary cost performance compared to its peers in Victoria and other jurisdictions.

UED's operating expenditure forecasts for the forthcoming regulatory period must ensure that UED has a reasonable opportunity to operate and maintain its assets in a satisfactory condition; and it must ensure that UED can adequately fund efficiently expenditure through its new business model. It is not appropriate to forecast UED's operating expenditure on the false assumption that its assets are not aging, that cost pressures are changing or that UED can or should avoid the costs associated with implementing a more effective business model that will deliver long term benefits to consumers by assuring costs remain efficient and service standards are maintained. However, while UED questions the AER technical competence to undertake some tasks in its preferred methodology, it does acknowledge that - properly applied - the AER's 'year 4' method can be used to 'stress test' UED's forecasts for its new business model.

UED has provided further substantiation of its original operating expenditure forecasts. Furthermore, UED has explained that:

- The forecast volume of work for outsourced services is consistent with 2009 actual data.
- The competitive tender exercise required bidders to submit budget forecasts, which comprise price and volume. Therefore, the AER is incorrect to conclude that the competitive tender process can be relied upon to set the unit costs, but not work volumes.
- The impact of errors in the forecast volumes for outsourced services would not have a major impact on actual operating expenditure.
- In-house costs are substantially "non-labour" rather than labour. Non-labour costs cannot be considered in "unit cost" and "work volume" terms as these costs include items such as travel and accommodation, rent and rates.
- In-house labour costs have been developed through a comprehensive benchmarking exercise in terms of staff numbers and wage rates.

In relation to the AER's 'year 4' roll forward approach to forecasting UED's operating expenditure, UED has identified that a number of inappropriate adjustments and escalators have been applied by the AER. For example, the AER has removed the costs of services provided by DUET and AMPCI, even though these services have been provided to UED for 7 years and have contributed to UED's efficient performance. In another instance, the AER has adopted the ESCV's assumed cost change for UED between 2009 and 2010. UED has explained that the ESCV's assumed cost change for UED does not seem to be reasonable. More importantly, however, it is not appropriate for the AER to use an out-of-date assumption, which was made by the ESCV almost 5 years ago. The AER should instead adopt appropriately calculated scaling and labour escalation rates, which UED submits should be 1.87% per annum.

If the AER's 'year 4' method is to stress test UED's operating expenditure forecasts it should ideally make an adjustment to account for differences between the existing and new business model. Similarly, it is important to recognise that the AER is using JAM's 2009 costs as a basis for forecasting UED's operating expenditure. As highlighted by Philip Williams in his independent expert opinion,it is not reasonable to assume that JAM would continue to provide these services at zero profit margin.

The AER's 'year 4' method updated to reflect UED's adjustments and corrections further demonstrates that UED's operating expenditure forecast for its new business model is reasonable and complies with the Rules. Specifically:

- UED's total operating expenditure forecast for the next regulatory period is $637.5 million, as shown in the table below.
- The correct application of the AER's year 4 roll-forward model indicates a total estimated operating expenditure for the same 5 year period of $668.7 million before any allowance is made for the additional outputs to be delivered by the new business model.

Furthemore, the available benchmarking evidence indicates that UED's operating expenditure forecasts satisfy the requirements of clause 6.5.6(c) of the Rules. In light of the available benchmarking information, Philip Williams comments that he finds it odd that the AER has rejected UED's operating expenditure forecast as not reflecting efficient and prudent costs.[74]

In the Revised Regulatory Proposal, therefore, UED is adopting the operating expenditure forecasts as set out below. Based on the evidence presented in this Revised Regulatory Proposal, the AER should accept UED's forecasts in accordance with clause 6.5.6(c) of the Rules.

Table 5-19: UED's forecast operating expenditure for the forthcoming regulatory period ($M in 2010 dollars)

	YEAR ENDING 31 DECEMBER					Total $M
	2011	2012	2013	2014	2015	
MAINTENANCE						
Routine	12.2	12.0	10.6	10.6	10.6	55.9
Condition based	12.6	10.5	10.5	10.5	10.5	54.6
Emergency based	6.7	5.8	5.8	5.8	5.8	30.0
Other maintenance	4.4	4.8	4.8	4.8	4.8	23.5
Sub-total maintenance	**35.9**	**33.1**	**31.7**	**31.7**	**31.7**	**164.0**
OTHER FUNCTIONS						
Network operating	31.3	31.6	32.1	32.0	32.1	159.1
SCADA/Network control	5.5	5.9	5.9	5.9	5.9	28.9
Billing & revenue	2.5	1.8	1.8	1.8	1.9	9.8
Customer service	7.8	8.2	8.2	8.1	8.2	40.4
Advertising	1.8	0.6	0.6	0.6	0.6	4.3
Regulatory	3.3	2.3	2.3	2.5	2.8	13.2
Self insurance	3.5	3.5	3.5	3.5	3.5	17.7
Debt raising	0.8	0.8	0.9	0.9	1.0	4.3
Other	39.5	40.5	39.3	38.7	37.6	195.8
Sub-total other functions	**96.0**	**95.2**	**94.6**	**94.0**	**93.6**	**473.5**

[74] Philip Williams, Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c), A report prepared for Johnson Winter & Slattery, July 2010, paragraph 71.

Total operating expenditure	**131.9**	**128.3**	**126.3**	**125.7**	**125.3**	**637.5**

Amounts shown in real 2010 terms.

6. Forecast Capital Expenditure

Key messages

UED's original Regulatory Proposal explained that

- UED's rate of network utilisation in its sub-transmission and zone substations has increased as UED has exploited opportunities to manage risk through the use of short-term ratings. New zone substations are required to meet demand growth and to improve the reliability of the primary distribution system.
- UED is projecting a reduction in customer-initiated capital benchmarks for the 2011-2016 period primarily driven by weaker economic growth forecasts compared to the current regulatory period.
- UED is entering a period in which the requirement for asset replacement expenditure will substantially increase, reflecting the age/condition profile of the asset population.
- Considerations of prudent safety, environmental and quality of supply management require that UED accelerates the replacement of neutral screen service wires. The installation of additional ground fault neutralisers in bushfire areas and harmonic fitters is also required to meet quality of supply obligations.
- UED will in-source its control room function as part of its business model transformation.
- UED IT capital expenditure must increase significantly to deal with end-of-life systems; respond to growing customer expectations; and to address UED's regulatory obligations.
- Total capital expenditure will increase from $556 million over the current period to $910 million in the forthcoming period.

The AER's Draft Decision concluded that the AER is not satisfied that UED's proposed forecast capex reflects the capex criteria under clause 6.5.7(c) of the Rules. This is based on the view that

- The Victorian DNSP's have historically underspent their forecast capex and they are again forecasting a significant increase.
- The AER regards UED's historical costs as efficient and a reasonable guide to future expenditure requirements. Network risks are capable of being managed within historical levels of expenditure.
- The Reliability and Quality Maintained capital expenditure is supported by models that are not appropriately calibrated. Nuttall Consulting's repex model calibrated to historic expenditure provides a more appropriate assessment of future replacement capital expenditure requirements.
- The Victorian DNSPs did not adequately provide a clear link in their regulatory proposals between the exercise of engineering judgement and the economic efficiency of the forecast.

Key messages

In this Revised Regulatory Proposal, UED:

- UED explains that historic capital expenditure is a poor guide to future expenditure requirements. The AER's reliance on this forecasting approach is inconsistent with the Rules requirements and the National Electricity Law. For UED, the AER's Draft Decision provides insufficient capital expenditure to maintain existing levels of reliability and compliance.
- For RQM capital expenditure, UED explains that it uses a bottom up approach based on coherent, reasonable and prudent asset management systems. This approach is consistent with good industry practice, and is vastly superior to the trend approach adopted by Nuttall Consulting and the AER.
- UED has undertaken further work to revise forecast energy, maximum demand and customer numbers based on the latest available data, taking into account the revised AMI schedule, GDP growth, latest summer peak demand data and revised air conditioner sales. This work confirms that the maximum demand and energy volume forecasts have both increased slightly from the UED's original Regulatory Proposal.
- UED's list of reinforcement projects has been developed following a well proven and sophisticated assessment process, considering load growth, utilisation, plant loading and customer load at risk. By contrast, Nuttall's approach is overly simplistic and appears to be without factual support, except for a comparison with historical expenditure. The probabilities used in assessing the timing of the projects appear to be totally subjective and without basis.
- UED rejects Nuttall Consulting's forecasting methodology for IT programs, which dismisses the final two years of a soundly based IT plan on the basis that it lacks of 'agility.' UED does not consider Nuttall Consulting's criticisms to be soundly based. For example, contrary to Nuttall Consulting's view, there is no experience of electricity distribution utilities using cloud computing services for delivering core business applications.
- UED has updated its assessment of labour and material escalators, and reflected this information in its revised capital expenditure proposals. UED considers that its revised capital expenditure forecasts presented in this submission are consistent with the Rules requirements and must be accepted by the AER. A reduced level of capital expenditure allowance will constrain UED's expenditure and adversely affect network reliability and compliance.

6.1 Introduction

This chapter sets out UED's response to the Draft Decision's assessment of UED's capital expenditure forecasts. It also details UED's revised capital expenditure forecasts for the purpose of this Revised Regulatory Proposal.

The chapter is structured as follows:

- Section 6.2 presents a summary of UED's overall response to the Draft Decision's assessment of UED's capital expenditure requirements.

- Section 6.3 presents a summary of the revised capital expenditure forecasts that have been adopted by UED for the purpose of this Revised Regulatory Proposal.
- Section 6.4 presents a recap on UED's forecasting methodology for capital expenditure.
- Sections 6.5 to 6.11 inclusive present UED's detailed responses to the Draft Decision in relation to each capital expenditure category, namely:
    - Reinforcement (Section 6.5);
    - Customer-initiated capital expenditure (Section 6.6);
    - Reliability and quality maintained (Section 6.7);
    - Environmental, safety and legal (Section 6.8);
    - SCADA and network control (Section 6.9);
    - Information technology (Section 6.10); and
    - Non network assets- other (Section 6.11).

6.2 Overview of UED's response to the AER's Draft Decision

6.2.1 Introduction

Incentive regulation should encourage distributors to deliver reliable network services efficiently and prudently. In terms of efficiency, distributors should be encouraged to find lower cost ways of maintaining network reliability and satisfying the distributor's compliance obligations. In terms of prudency, distributors must plan and maintain the network to withstand worse-than-expected conditions, whether in terms of customer maximum demand; the number of new network connections; asset condition and failures; risks to health and safety; storm activity; and climate change.

To deliver network services more efficiently distributors must find smarter ways of maintaining, renewing and reinforcing the network. This requires better information on asset condition and performance as well as the adoption of better risk management techniques. UED has already delivered significant efficiency improvements through the adoption of best practice asset management techniques. For example, UED adopts a probabilistic approach to planning which accepts a risk of loss of supply in circumstances involving outage of plant items at infrequent times of high network loading.

Typically, two important consequences follow from the achievement of more efficient network services:

- Customers obtain distribution services at lower prices because capital expenditure is lower than would otherwise be the case. This reduction in prices is achieved because the savings in capital expenditure are reflected in a lower regulatory asset base.
- The network may be operating at higher levels of utilisation and risk than previously. Whilst this level of utilisation and risk may be regarded by the distributor as prudent,

further increases may be unacceptable in terms of the risks to network reliability. For example, UED has reduced its reinforcement capital expenditure by exploiting opportunities to manage risk through the use of short-term ratings. As a consequence, however, the rate of network utilisation in UED's sub-transmission and zone substations has now increased to a prudent maximum, and current low levels of reinforcement capital expenditure will not be possible.

It follows from the above observations that efficiency improvements may involve the deferral of capital expenditure. However, the lower levels of capital expenditure achieved during periods of deferral cannot be maintained indefinitely. Maintaining historic levels of capital expenditure in these circumstances could only be achieved if network reliability were allowed to deteriorate, which would be contrary to the requirements of the Rules. As a consequence, current levels of capital expenditure are a poor guide to future expenditure requirements.

In terms of planning processes, UED has developed a comprehensive Asset Management Plan to facilitate the efficient and prudent delivery of reliable network services. The AER engaged Nutall Consulting to provide an independent review of UED's capital expenditure forecasts. As noted in Chapter 4 of this Revised Regulatory Proposal, the scope of the review undertaken by Nutall Consulting included a desktop review of the capital governance practices of UED, as defined in its documented policies and practices provided in support of its original Regulatory Proposal.

The Nutall Consulting report[75] contained a number of very positive findings and conclusions regarding the quality of UED's asset management planning. Page 41 of the report states:

> "PAS 55:200811 (PAS 55) is a Publicly Available Specification that was developed in response to demand from industry for a standard relating to asset management in infrastructure intensive industries. The approach we have taken to assess DNSP governance documentation against the capex governance requirements is to frame an appropriate subset of criteria derived from PAS 55 and then to assess the documentation against this set of criteria.
>
> Nuttall Consulting considers that the documentation provided by each of the five Victorian DNSPs incorporate well-evolved, fit-for-purpose capital governance processes and practices. They are based on asset management frameworks that have been developed with varying degrees of reference to the PAS 55:2008 standard."

Nutall Consulting assessed each DNSP's asset management documentation against six criteria derived from PAS 55. In UED's case, Nuttall Consulting rated the documentation as "High" against 5 of the 6 criteria. UED's governance and capital expenditure planning processes have been accepted by the AER's consultant as fully satisfying the PAS 55 requirements.

Nuttall Consulting's findings in relation to UED's capital expenditure plans and governance processes are highly relevant to the AER's assessment of UED's capital expenditure forecast for the forthcoming regulatory period. Specifically, the AER should have confidence that UED has asset management processes and strategies in place to ensure that network services are delivered efficiently and prudently.

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[75] Nutall Consulting, Report – Capital Expenditure, Victorian Electricity Distribution Revenue Review, Final Report to the AER, 4 June 2010.

UED's original Regulatory Proposal provided very detailed information to explain and substantiate its capital expenditure forecasts.

UED is very concerned that Nuttall Consulting's approach to assessing UED's capital expenditure is inconsistent with good industry practice. In particular, Nuttall Consulting has not accepted that UED's sound planning and governance processes can be relied upon to deliver efficient and prudent capital expenditure forecasts. Furthermore, however, Nuttall Consulting has also resisted a detailed examination of UED's capital expenditure plans. Instead, the review approach has relied on:

- a general proposition that historic capital expenditure provides a good guide to future requirements;
- an assertion that as plans progress through the capital approval process an overall saving will be achieved;
- a simplistic replacement capital expenditure spreadsheet which does not reflect standard asset lives, but instead adopts the asset lives implied by recent expenditure levels; and
- an approach to reinforcement capital expenditure which assumes that any proposed capital expenditure can be reduced by at least 10%.

Nuttall Consulting's approach to the review is best described as unorthodox. In UED's view, it is inconsistent with good industry practice and cannot be regarded as a sound approach to assessing UED's capital expenditure forecasts or developing alternative estimates. The AER's over-reliance on historical data and its inadequate consideration of the expenditure required to meet the capital expenditure objectives leaves UED exposed to the likelihood that it will be unable to recover the efficient costs incurred in providing reliable network services to customers. The AER has also failed to recognise that the cost to customers of under-investment far exceeds the costs of over-investment.

Given the shortcomings in Nuttall Consulting's review, the AER's Draft Decision is not consistent with the requirements of the Rules or the National Electricity Law. In particular, the AER has failed to have proper regard to Revenue and Pricing Principles in section 7A of the National Electricity Law, which requires the AER to consider the potential risks of under investment and the over utilisation of the network. Both of these outcomes are highly likely to occur if the AER's Draft Decision were implemented. In addition, the expenditure levels set out in the Draft Decision would lead to a decline in network reliability and compliance, which would also be contrary to the Revenue and Pricing Principles and the capital expenditure objectives in the Rules.

In conducting its review of UED's revised capital expenditure proposals, UED suggests that the AER focus on the following broad indicators of capital expenditure requirements:

Unsustainably low levels of capital expenditure will be indicated by:

- Worse than targeted levels of reliability and trends of deterioration in unplanned SAIFI or unplanned SAIDI;
- An increasing trend in the annual load at risk;
- Over utilisation for network equipment for both distribution and substransmission (leading to cyclic overloads beyond design parameters);

- Accelerated deterioration (condition) of assets due to higher asset operating temperatures resulting in decreasing trend in the remaining life of assets; and
- Increasing equipment failure rates.

Increases in historical capital expenditure will be warranted if:

- Maintaining current levels of expenditure would lead to a deterioration of service;
- Benchmarks indicate that the current level of expenditure is below comparable businesses;
- Network and asset management practices are shown to be well-evolved and fit for purpose and indicate increased risks to customer load;
- New obligations are to be imposed on the business; and
- Maximum demand is expected to increase.

In the remainder of this section, UED provides a brief summary against each of these factors to highlight the key drivers that underpin UED's proposed increase in capital expenditure for the forthcoming regulatory period.

6.2.2 Deterioration in Service

In the current regulatory period expenditure on demand reinforcement projects has exceeded the regulatory allowance and there has been an underspend on Reliability and Quality Maintained and the Environmental, Safety and Legal categories of the capital budget. UED has also overspent its Reliability and Quality Improvement category of the budget, by delivering lower-cost high-value reliability projects in order to efficiently defer higher-cost replacement capital expenditure.

However, opportunities to apply such improvement programs have been largely exhausted with any new reliability programs being more costly and less effective. As such asset replacement programs are now the most efficient means to address deteriorating assets to maintain reliability.

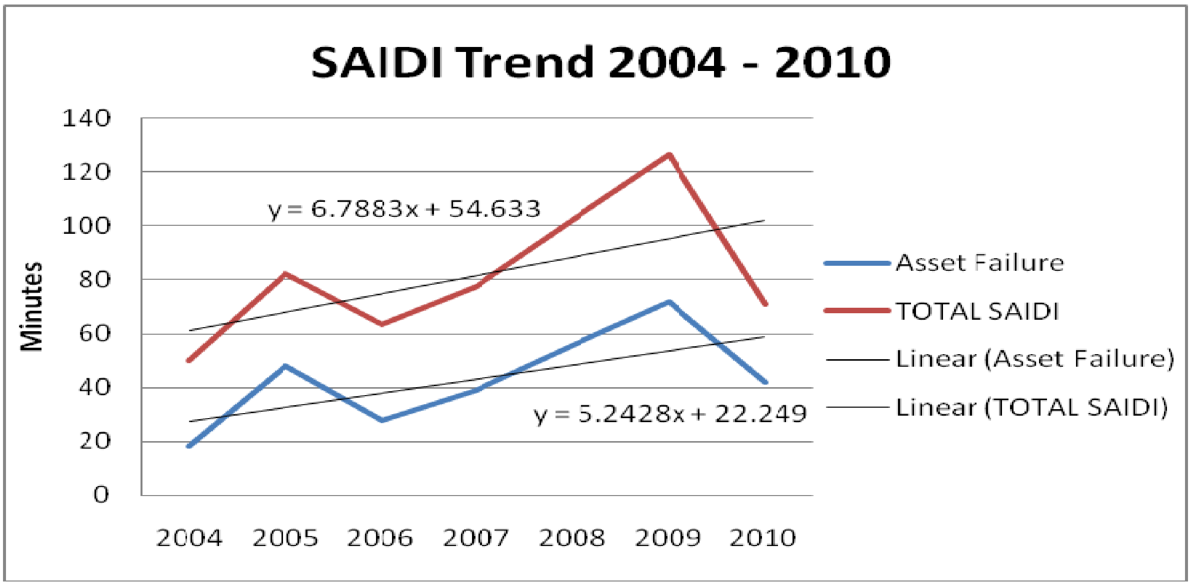
Nuttall Consulting's simplistic modelling of Reliability and Quality Maintained capital expenditure requirements uses historical expenditure as a key driver ignores the above adopted strategies therefore failing to accurately reflect the condition of assets and therefore under-estimates the amount of expenditure required for replacements.

6.2.3 Deteriorating Trends in Reliability

UED has analysed its networks reliability performance in the years from 2002 to 2010. The analysis adjusted the results for the impact of non-distribution network events, such as transmission outages.

The analysis is displayed graphically below, along with data on asset failure rates (dealt with in more detail in the sub-section following):

Figure 6-1: SAIDI Trend 2004 - 2010



UED's analysis confirms an underlying trend in SAIDI which is deteriorating at an annualised increase of 6.8 minutes per year of which 5.2 minutes is caused by asset failure.

This is clear evidence that increased capital expenditure (above historical rates) is required to prevent further deterioration in supply reliability and then to reduce the SAIDI levels to the AER's target levels.

6.2.4 Increasing Asset Failure Rates

The overall number of asset failures in the period of 1999 to 2008 indicates an increasing trend of approximately two per cent per annum. This is consistent with an age profile of the assets where the average age of each asset class is increasing with an attendant trend of declining asset condition. This is entirely consistent with a significant portion of the assets having been installed in the 1960's and are approaching the end of the physical (and economic) life.

The increasing rate of asset failure is an indication that UED's network is entering a period in which the requirement for asset replacement will substantially increase. UED's increase in proposed expenditure reflects this and is the minimum amount required to operate the network in a prudent manner.

6.2.5 Decreasing Remaining Life of Assets

In its original Regulatory Proposal, UED explained that it engaged the services of PB Power to develop a model to test UED's replacement capital expenditure. The AER has rejected UED's forecasts and instead relied on a model developed by Nuttall Consulting.

Both the PB and Nuttall replacement models, which are based on expected asset life, predict that a significant increase in expenditure over historical levels is required. The two models estimate a different level of expenditure, based on different assumptions about asset life, but both predict that more assets will be at the end of their lives, and more assets will require replacement (based on condition). As predicted by the models, and as backed up by in-service inspection and an increase in failure rates, the historical levels of expenditure are not sufficient to maintain the assets in their current state. On historical expenditure levels, the number of assets reaching the end of their life and requiring replacement will continue to increase over the next five years.

A full analysis, demonstrating that the replacement levels forecast by the PB model still result in an increase in the proportion of assets exceeding their nominal life is provided in the paper "UED Forecast Asset Replacement Volumes" which is provided in support of this submission.

6.2.6 Increasing Load at Risk

UED's current expenditure levels on reinforcement capex has resulted in assets in the majority of zone substations exceeding their 24 hour N-1 rating, subtransmission loops exceeding their N-1 rating and distribution feeders being loaded above their planning criteria levels. This is shown clearly in UED's 2009 Distribution System Planning Report, which also shows that customers are increasingly exposed to significant load at risk across the UED network, as evidenced by the two figures below.

Figure 6-2: Distribution Feeder loading

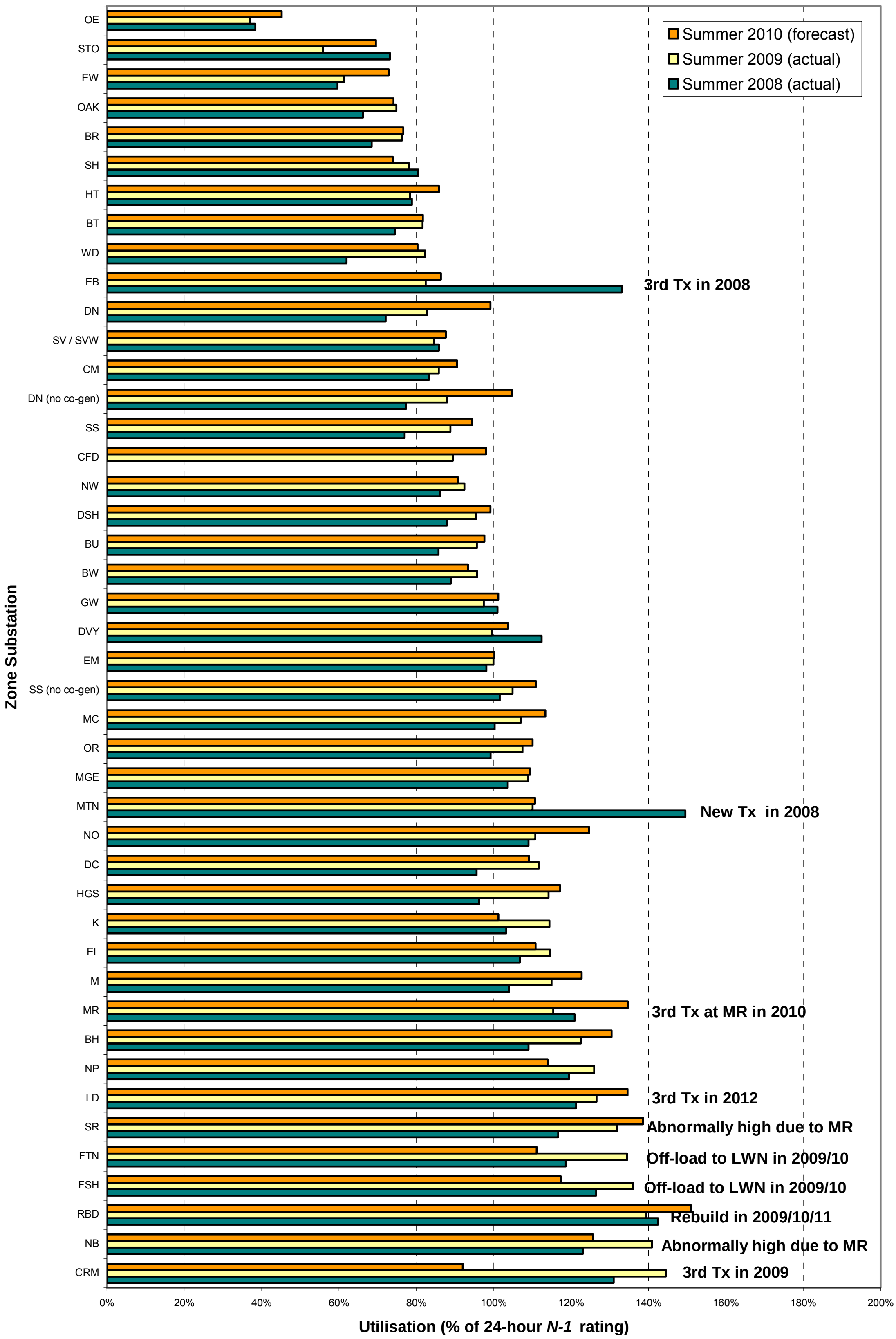
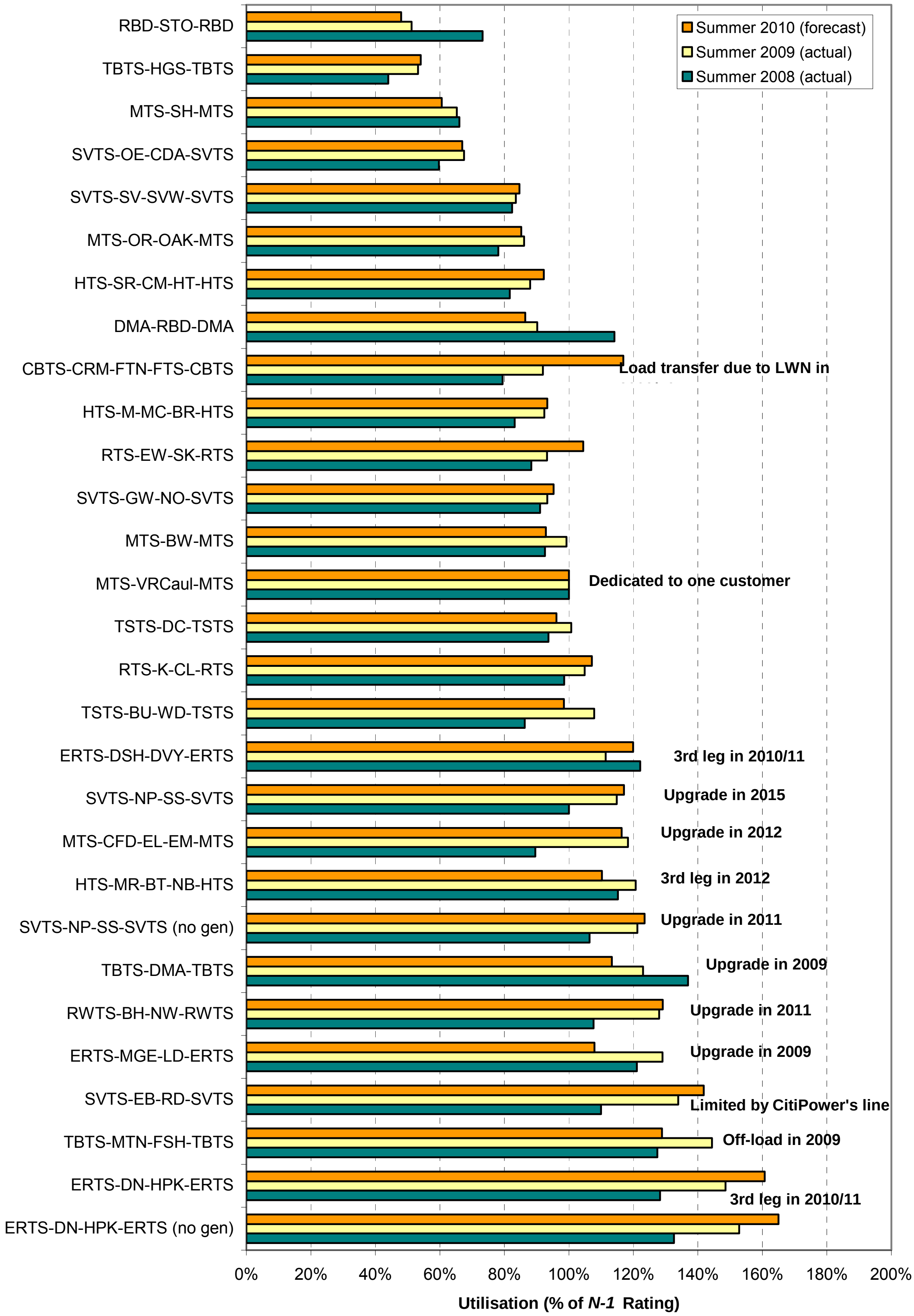


Figure 6-3: Subtransmission Loop Loading



6.2.7 Increasing Utilisation Rates

The average summer utilisation for sub-transmission loops in the summer of 2008/09 reached 102 per cent. Utilisation rates on the sub-transmission system have increased from under 90 per cent to above 100 per cent in the regulatory period. In the same period n-1 zone substation utilisation increased from 93 per cent to 101 per cent and distribution feeder utilisation increased from 58 per cent to 67 per cent.

With forecasts of continuing load growth utilisation will remain above 100 per cent through the entire 2011-16 period. These rates of utilisation are unsustainably high. Indeed, the above utilisation rates are a result of large sections of the network being very heavily loaded compared to networks in NSW and QLD (for example). The forecast increase in load will require augmentation projects and a step increase in capital expenditure to avoid substantial increases in customer load at risk and reduce utilisation to more levels that will avoid catastrophic load loss in very high risk events

6.2.8 Benchmarks

The AER has undertaken some preliminary benchmarking of the Victorian DNSP's against their interstate counterparts in NSW and Queensland. Benchmarking has been performed by comparing capital expenditure against asset base; numbers of customers; peak demand; line length; and energy distributed.

The benchmarking indicates that Victorian DNSP's individually and collectively are efficient compared with their peers in Queensland and New South Wales. In fact, the benchmarks indicate that the Victorian expenditure levels are on average 35 per cent more efficient when measured against NSW and 58 per cent more efficient when measures against Queensland. We note that Country energy with a customer base of approximately 1.3M has received more capex in total ($3.8 billion (real 2008/09 terms) from the AER's NSW review than all the Victorian businesses combined, which have 2.6M customers. In other words, Country Energy received more than twice as much capital per customer as did the Victorian businesses. Overall, the three NSW DNSP's were allowed some $13.8 billion (real 2008/09) and serve some 3.8M customers (an average some 2.7 times higher than all Victorian DBs). Queensland distribution companies did even better, receiving four times as much per customer as their Victorian counterparts. Other parameters such as 'line length' can only explain a small component of these differences.

UED accepts that there are differences in geography, service area, customer mix and other factors that impact on benchmarking parameters. But UED cannot accept as reasonable the assertion that the AER has applied the same approach in assessing all DNSPs in these three regions. Even if the AER has applied the same approach, the very substantial differences in this simple comparison is clear evidence that that approach does not deliver outcomes for UED that are consistent with the requirements of the Rules.

UED's proposed net capital expenditure for 2011 to 2015 of $790 million is clearly efficient by any reasonable approach when compared with its peers in NSW and Queensland.

6.2.9 Network Governance

The AER's consultants (Nuttal Consulting) have also reviewed the capital governance practices of UED. The results of the review are as follows:

- Policy and Strategy: High
- Asset management Information: Partial
- Risk Management – identification and control of risks: High
- Capex Planning: High
- Implementation and operation: High
- Checking and corrective action: High
- Management Review and continual improvement: High

The AER's consultants concluded that UED's documentation demonstrated a well developed capital governance process and practices that, if followed, would be expected to deliver prudent and efficient outcomes for its stakeholders.

A well developed capital governance process provides evidence that capital expenditure is properly targeted and efficiently deployed and that networks are efficiently and prudently run. On this basis and with the additional AMP information i.e. planning reports and strategic planning papers that have been provided to the AER, there is every reason to conclude that the capital expenditure program proposed by UED is reasonable, prudent and efficient.

UED has developed a balanced approach to maintenance and asset replacement, proposing substantial investments to arrest deterioration of aged assets and to reverse the observed decline in service reliability. Emphasis is being shifted from reactive (responding to failures) to pro-active (using a combination of preventative, condition based and time based) expenditure with a clear business objective of achieving long term cost minimisation. This clear business strategy is reflected in the changed business model described above.

UED acknowledges that implementing this business strategy is a principal contributor to the forecast increase in the proposed asset Reliability and Quality Maintained (replacement) capex. However, based on the evidence of deteriorating asset condition and declining reliability performance, this change in strategy is essential to ensure UED can meets its obligations under law, regulations and the Rules and continue to deliver services at standards reasonably expected by customers.

6.2.10 New Obligations

As discussed in section 6.8 below, new legislation has imposed additional obligations on UED. In developing at the Electrical Safety Management Schemes (ESMS), UED has performed extensive safety workshops to identify strategies to manage the network. UED is now obligated to deliver the capital programs that were the outcomes of these workshops.

6.2.11 Summary

The material in this submission includes evidence that demonstrates:

- Continuation of historic and current levels of capital expenditure will compound the observed deteriorating service levels.

- Benchmarks indicate that the current level of expenditure is below comparable businesses.
- Network and asset governance practices have been shown to be well evolved and fit for purpose.

UED contends that the current levels of expenditure are not sufficient to maintain the network's ability to deliver levels of performance that customers quite reasonably, have come to expect. Continuation of current levels of expenditure will not arrest current trends (if unabated) which are for further deterioration, rising equipment failures and increasing unreliability.

UED has estimated that continuation of current trends will cause a SAIDI increase of up to 6.5 customer minutes per annum (33 minutes in total) off supply by the end of the forthcoming regulatory period. UED's proposed increase in the capital expenditure will fund a number of asset replacement programs to maintain network performance within levels expected by customers.

UED uses a structured process for capital planning that combines informationon asset condition, the best available information for demand growth, engineering knowledge and practical experience to define the future requirements of the network, its future condition, performance and risk. We believe this approach is best practice and results in a robust capital works program that is efficient and prudent.

6.3 Overview of UED's revised capital expenditure forecasts

Table 6-1 below shows a comparison of the capital expenditure forecasts contained in UED's original Regulatory Proposal and those contained in the Draft Decision.

Table 6-1: Comparison of UED's original net capital expenditure forecasts and Draft Decision (2010 dollars)

	YEAR ENDING 31 DECEMBER					Total ($ million)
	2011	2012	2013	2014	2015	
UED's original Regulatory Proposal	179.5	169.3	164.9	148.5	127.8	790.8
Draft Decision	107.9	107.3	102.6	106.2	107.7	531.5

In light of the AER's Draft Decision and UED's response (summarised in Section 6.2 above, and detailed in the remainder of this Chapter), UED's revised capital expenditure forecast for each category for each year of the forthcoming regulatory period is shown in Table 6-2.

Failure by the AER to accept these forecasts will inevitably present conflicts with the pressures imposed on UED by private capital and debt markets and leave UED and its Board in a position where it has no alternative but to make practical capital rationing decisions that result in further deterioration of asset condition and service standards. This would expose UED to punishingly high penalties under the Victorian service incentives scheme. Such a situation and its outcome are totally unacceptable to UED.

Table 6-2: UED's revised capital expenditure forecasts for standard control services (2010 dollars)

	YEAR ENDING 31 DECEMBER					Total
	2011	2012	2013	2014	2015	$M
SYSTEM ASSETS						
Reinforcements	45.0	48.2	49.5	40.9	30.4	214.0
Customer initiated	53.4	51.8	50.1	49.0	47.3	251.7
Reliability & Quality Maintained	61.8	58.9	57.1	50.8	51.8	280.3
Reliability & Quality Improvements	0.0	0.0	0.0	0.0	0.0	0.0
Environmental, Safety & Legal	22.4	15.5	13.1	9.8	9.3	70.1
Sub-total system assets	**182.6**	**174.4**	**169.8**	**150.6**	**138.8**	**816.1**
NON-NETWORK ASSETS						
Non-Network General Assets – IT	23.5	36.5	27.6	16.0	7.2	110.9
SCADA and network control	0.0	0.7	3.9	0.0	0.0	4.7
Non-Network General Assets – Other	8.8	4.3	2.5	2.8	2.5	20.9
Sub-total non-network assets	32.3	41.5	34.0	18.8	9.8	136.5
Total capital expenditure	**214.9**	**215.2**	**200.0**	**169.4**	**148.5**	**952.6**
Less – Customer contributions	27.7	27.0	26.5	26.8	26.0	134.0
NET CAPITAL EXPENDITURE	**187.2**	**188.2**	**173.5**	**142.6**	**122.5**	**818.6**

Amounts shown in real 2010 terms.

UED's detailed response in relation to each category of capital expenditure is provided in Sections 6.5 to 6.11 of this Chapter. Before turning to these detailed responses, section 6.4 recaps on UED's forecasting methodology for capital expenditure as set out in its original Regulatory Proposal.

6.4 Recap on UED's forecasting methodology for capital expenditure

As noted in section 6.2 above, UED commissioned a report from KPMG to review UED's forecasting methodologies for operating and capital expenditure. KPMG's independent report confirmed that the design and application of UED's forecasting methodology for capital expenditure is consistent with Rules requirements in producing forecasts that:

- reasonably reflect:

- o the efficient costs of achieving the capital expenditure objectives;
- o the costs that a prudent operator in the circumstances of UED would require to achieve the capital expenditure objectives; and
- o a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives;

- comply with the requirements of the Rules that relate to the preparation of expenditure forecasts, and any relevant regulatory information instrument; and
- are properly allocated to direct control services in accordance with the principles and policies set out in UED's Cost Allocation Method.

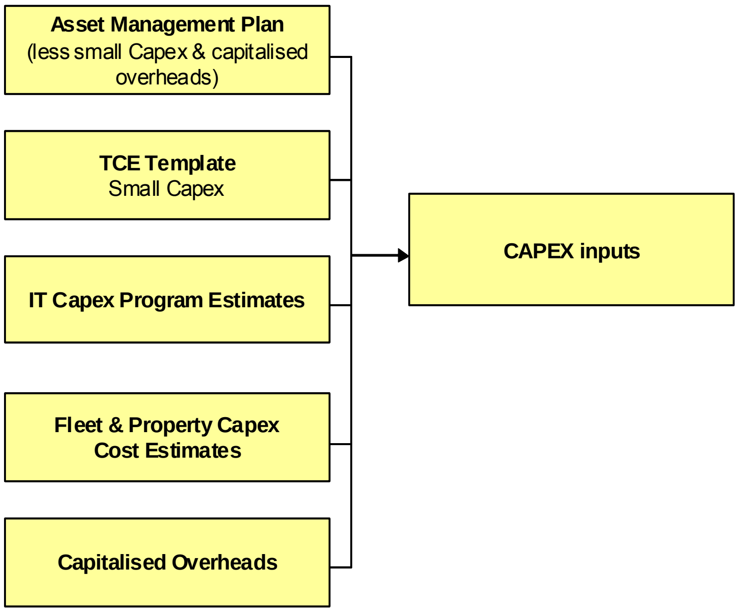
In terms of its expected growth in demand for standard control services, UED's original Regulatory Proposal adopted the following forecasts of maximum demand, energy and customer numbers.

Table 6-3: Regulatory Proposal assumptions on customer numbers, energy and demand

	2011	2012	2013	2014	2015
Customer numbers	630,193	634,296	637,563	641,373	646,457
Energy (Gwh)	7,793	7,734	7,592	7,478	7,486
Maximum demand 10th percentile (MW)	2,181	2,253	2,296	2,390	2,434
Maximum demand 10th percentile (MW)	1,992	2,061	2,102	2,142	2,180

Figure 6-4 below briefly summarises the components of forecast capital expenditure that are captured and summarised by the model used by UED to forecast its capital expenditure requirements.

Figure 6-4: Capital expenditure forecast components



Source: AT Kearney.

Aggregate capital expenditure forecasts are built up from the five components illustrated in the above diagram, as discussed briefly below.

6.4.1 Network asset management plan

UED's original Regulatory Proposal explained that its asset management plan contains detailed information on the key inputs and assumptions, including load growth, and planning standards that underpin UED's capital and operating expenditure forecasts. UED's AMP was provided as an appendix to UED's original Regulatory Proposal.

6.4.2 "Small" capital expenditure

The high-volume low-unit-cost expenditure ("small capex") required to meet the AMP (and included in the AMP) has been estimated by reference to the unit costs and capitalised costs provided by JAM in the AMP, and substituting in their place, the open market unit prices tendered by the successful bidder contractor and UED overheads are capitalised in accordance with UED's accounting policy.

6.4.3 Information Technology (IT) capex program estimates

IT capital volumes are based on an IT plan prepared by independent advisors Deloitte. The IT plan formed part of UED's original Regulatory Proposal.

6.4.4 Fleet and property capex estimates

UED's AMP outlined a replacement program for its existing fleet of 143 vehicles over the forthcoming regulatory period. UED's property capital expenditure related to:

- the fit-out of a new control room required under UED's new business model which separates the existing network into two sub-networks for operational purposes; and
- a new depot.

6.4.5 Capitalised Overheads

Both UED internal costs and service-provider costs incurred indirectly in the delivery of UED's capital expenditure program are capitalised in accordance with UED's capitalisation policy. The assessment of capitalised overheads is made on an activity or sub-activity basis according to the percentage of activity involved in the delivery of the UED capital program.

6.5 Reinforcement capital expenditure forecast

6.5.1 UED's Regulatory Proposal

Reinforcement capital expenditure represents capital expenditure required to meet growth in demand attributable to existing customers on the network due primarily to increasing penetration of air-conditioning in existing housing stock. It consists of expenditure in the following main categories:

- sub-transmission lines;
- zone substations;
- HV distribution feeders;
- distribution substation upgrades; and
- LV feeder augmentation.

UED's original Regulatory Proposal explained that its proposed reinforcement capital expenditure was required in order to:

- meet regulatory obligations in relation to the maintenance of quality, reliability and security of supply of standard control services;
- reinforce the network to the extent necessary to meet customer load growth whilst on average maintaining appropriate levels of performance and levels of risk for customer loss of supply; and
- facilitate viable embedded generation projects.

UED's original Regulatory Proposal explained that UED adopts a probabilistic approach to planning which accepts a risk of loss of supply in circumstances involving outage of plant items at infrequent times of high network loading. In recent years, UED noted that its rate of network utilisation in its sub-transmission and zone substations has increased to a prudent maximum as UED has exploited opportunities to manage risk through the use of short-term ratings. For the forthcoming regulatory period, UED also explained that it is adopting a higher value for customer reliability, consistent with Charles River Associates estimate for VENCorp (now AEMO) in September 2008.

UED's original Regulatory Proposal also explained that substation utilisation in some areas now exceeds optimal levels. This assessment is consistent with information contained in UED's latest Distribution System Planning report. Table 6-4 below presents a high level summary of number of assets which exceeded their thermal rating in summer 2007/08.

Table 6-4: Assets exceeding thermal rating during Summer 2007/2008

Network Elements	Total number of elements	Number of assets exceeded their rating in summer 2007/08
Zone Substations	45	23 exceeded their 24-hour N-1 rating (after corrected for network abnormalities)
Sub-transmission Loops	27	13 exceeded their N-1 rating (after corrected for network abnormalities)
HV Distribution Feeders	396	90 were loaded beyond 85% of their rating (after corrected for network abnormalities)

UED's original Regulatory Proposal provided a summary of major augmentation works planned for UED over the period from 2009/10 to 2015/16. The proposed works included new zone substations to meet demand growth and to improve the reliability of the primary distribution system. UED's strategic planning studies identified the location of these new zone substation sites, and the power line corridors to enable connection of new zone substations and improve the security of the sub transmission system.

Compared with the current period's actual level of expenditure, UED proposed a significant increase in reinforcement expenditure over the forthcoming regulatory period. UED noted that the increase in reinforcement expenditure for the forthcoming regulatory period reflects the higher assumed value of VCR and the relatively high present level of asset utilisation.

6.5.2 AER's Draft Decision on reinforcement capital expenditure

The AER was not satisfied that UED had justified that the proposed increase in forecast reinforcement expenditure reasonably reflects the capital expenditure criteria. The AER considered that greater emphasis should be given to historical expenditure as a basis for forecast expenditure. The AER imposed a substantial reduction in UED's forecast expenditure allowing only 63 per cent UED's forecast.

Table 6-5: Reinforcement Reductions

	2011	2012	2013	2014	2015	Total
UED Proposal	44.6	41.2	44.5	42.5	32.1	205.0
AER	24.7	25.2	25.7	26.2	26.7	128.4

The AER also raised concerns about the accuracy of the peak demand, energy consumption and customer number forecast used as a basis for reinforcement capital expenditure. The AER was critical of the lack of consistency between UED's bottom up forecasts and the top down forecasts produced by NIEIR.

UED use a 10 per cent POE hot sumer day rather that a 50 per cent POE to calculate peak demand and the AER's consultant, Nuttall Consulting, believes that use of the 10 per cent POE will bring forward some marginal reinforcement projects which would otherwise be justified in future regulatory periods. Nuttall Consulting argued that if 50 per cent POE was used instead, it would affect the timing of the projects and result in deferrals of projects by up to three years. Nuttall Consulting concluded that the UED's process is not an unbiased estimator for future prudent and efficient expenditure and that the increase in expenditure has not been justified.

Nuttall Consulting also expressed an opinion that, as all projects have not had a detailed business cases prepared, there was some likelihood that synergies and optimisation will be identified during the capital governance process that will result in a reduction of expenditure.

Nuttall Consulting reviewed six projects to determine the likelihood of that project expenditure will be required as proposed by UED and used this to estimate the likelihood of expenditure for the whole program.

6.5.3 UED's response to the AER's Draft Decision on reinforcement capital expenditure

UED has undertaken further work to revise forecast energy, maximum demand and customer numbers based on the latest (2009) available data, taking into account the revised AMI schedule, GDP growth, latest summer peak demand data and revised air conditioner sales. In addition, a reconciliation has been prepared between NIEIR's top down estimates and UED's bottom-up estimates and UED's view on diversity factors. The updated NIEIR report is included as an appendix to this submission.

Overall, this work confirms that the maximum demand and energy volume forecasts have both increased slightly from the original submission. The overall effect of these changes has been to bring forward slightly the proposed capex program, but otherwise the cost of the program has not been materially affected.

UED has also reviewed the timing of the projects in line with the AER's comments and the most recent data. There is one project - the sub NO transformer project - which is no longer expected to take place in the forecast period. In addition, the work required at subs SV and SVW for the Telstra data centre project has been delayed by one year from 2010 to 2011 and now will come into the forecast period. The result of the changes in timing to these two projects is to reduce forecast expenditure by $3.4million.

As noted above, the AER criticised the use of 10 per cent POE for the development of maximum demand forecasts as the industry has widely used a 50 per cent POE. UED contends that its use of 10 per cent POE is consistent with forecasts accepted by the Office of the Regualtor General in the 2001-05 review and by the Essential Service Commission in the 2006-10 review; and that basis alone is justified. In addition, UED notes specifically that its network planning criteria allows for major network elements to operate well above the N-1 rating during critical network loading conditions. Adopting a 50 percent POE criteria would substantially increase the risk to customer load in these peak loading conditions. UED does not accept this as a reasonable imposition on customers.

The medium growth scenario with 10 per cent probability of exceedance (1 in 10 years) with due regard to energy policies of federal and state governments has been chosen as the basis for projection of capital expenditure. The reasons for adopting the ten per cent probability of exceedance are:

- UED has amongst the highest network utilisation rates in Australia as a consequence of a deliberate policy to maximise the efficient use of network assets;
- Load growth forecasts carry a degree of uncertainty in predicting both the economic conditions and the summer weather.[76] The degree of uncertainty increases as one moves from the bulk supply point into zone substations, then HV feeder, then distribution substations and finally LV feeder levels. This combined with the already high network utilisation mandates that a 10th percentile probability of exceedance scenario should be adopted as an appropriate risk minimisation strategy;
- To avoid the situations that have occurred in Western Australia, NSW and Queensland in 2002/03/04 where extreme summer peak demand exceeded supply capacity, it is both reasonable and prudent for demand reinforcement expenditure to be based on a medium economic growth scenario and 10 per cent probability of exceedance;
- The difference between 10 per cent and 50 per cent PoE maximum demand forecasts is not large (up to 8 per cent). The difference between the corresponding energy at risks associated with 10 per cent and 50 per cent PoE forecasts at time of augmentation is even much smaller. As the timing for augmentations are made based on the outcome of the value of expected unserved energy, the selection of 10 per cent PoE is not critical in economic justifications;
- 10 per cent PoE forecasts are mainly used as a trigger for further investigation (rather than being the main and the only driver for augmentation) for UED so that there is sufficient time to prepare and implement suitable plans;
- UED's overall peak demand exceeded its 10 per cent PoE forecast by 67MW in summer 2008/09;

In UED's project justification process, the timing of projects is determined by the time when the risk-adjusted value of customer lost load exceeds the NPV of the augmentation cost (and thus economically justifies the project not by the maximum demand. As the value of energy at risk during a 10 per cent POE year is not materially different from a 50 per cent POE year, there is no material effect on the timing of the projects. UED has traditionally used this methodology and can demonstrate that it produces a reasonable and prudent forecast of the requirement for reinforcement capital expenditure on a project level basis, having committed more than the allocated reinforcement capex provision in the current regulatory period. Nevertheless, as noted previously, the present levels of expenditure has not been sufficient to keep pace with the observed increase in network utilisation and further load growth requires a step change in expenditure as utilisation rates approach practical maximum levels(and customer load at risk increases beyond acceptable levels). UED has used a 10 percent POE hot summer day maximum demand as a key element of its comprehensive probabilistic planning for many years. Nuttall Consulting states that UED is

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[76] The current practice in the electricity industry in regard to assumptions about climate data records differs markedly from practices that are now widely accepted in the water industry across Australia. The impact of these differences is that the POE ratings indicated here almost certainly underestimate the risk of maximum temperature impacts on network loading.

the only Victorian DNSP that uses a 10 per cent POE. UED is the only Victorian DNSP that has adopted such a comprehensive probabilistic approach to planning which includes a demand forecast based on a 10 percent POE hot summer day. If Nuttall Consulting's contention that a 10 per cent POE results in projects being undertaken earlier than required, this would manifest as greater network capacity than required and would be demonstrated as lower network utilisation. UED's actual percent utilisation demonstrates beyond any doubt that such a contention is simply not correct.

The AER's consultant, Nuttall Consulting, also concluded that a reasonable estimate of reinforcement expenditure would be more in line with a historical trend. UED totally rejects that conclusion and restates its contention that a forecast based on the best available forward-looking information regarding load growth and network loading is the only reasonable and acceptable basis for forecasting reinforcement expenditure, particularly as the methodology has proved to be a reliable predictor of expenditure in the current regulatory period. Such a planning approach is entirely consistent with principles of good asset management, consistent with PAS55 and consistent with power distribution planning 'good industry practice'. Nuttall Consulting's approach based on forward planning by taking past planning circumstances into account will lead to simple continuation with past expenditures with no regard for future requirements.

Nuttall has also asserted that there is a likelihood that some projects will be deferred as a result of a more detailed evaluation process associated with project approval which will occur as part of the capital governance project. In the absence of detailed project justifications, Nuttall Consulting has applied a simple subjective discount factor to represent the likelihood of these projects proceeding, based on his own professional judgement. A weighted average probability is then applied to the proposed reinforcement program.

As explained in UED's original Regulatory Proposal, UED's list of reinforcement projects has been developed following a well proven and sophisticated assessment process, considering load growth, utilisation, plant loading and customer load at risk. By contrast, Nuttall's approach is overly simplistic and appears to be without factual support, except for a comparison with historical expenditure. The probabilities used in assessing the timing of the projects appear to be totally subjective and without basis.

UED has traditionally produced detailed business cases for projects in the 12 months prior to their execution. Since preparation of the original Regulatory Proposal, UED has produced strategy papers for the major projects with a value above $5 million. These papers justify the projects and their timing. UED concurs with the AER that historical expenditure does have some value as a sanity check, but information and data relating directly to forecast capital expenditure requirements is always superior to historic data.

Nuttall Consulting has asserted that there is some probability that the projects may be delayed until the next review period or will not go ahead. UED accepts that the timing of some projects will change because there is always an element of uncertainty associated with forecasts of load growth and maximum temperature. But this uncertainty is manifested both ways. That is, using the best available information would produce a forecast in which there is an equal probability that some projects presently planned for the 2016-20 regulatory period may be required to be brought forward. UED believe that by making decisions based on the best data available, is most likely to deliver a reasonable forecast of expenditure.

UED also note that Nuttall Consulting's methodology provides a maximum probability of going ahead of 90 per cent even for projects with high probability of being required. Effectively, this means that Nuttall's reinforcement capex forecast will always be arbitrarily discounted by at least ten percent less than any reinforcement capex proposal based on sound good industry practice planning approaches. The validity of such a 'mandatory' discount cannot and has not been substantiated. Nuttall Consulting's choice of probabilities appears to be subjective with no reasoning or basis givena and will always be at least ten percent less that UED's. Nuttall's choice of probabilities appears to be subjective and entirely without basis. UED use the customer value of expected unsupplied energy (EUE) to represent the risk of not implementing or delaying a project. When the risk exceeds the annualised cost of the option, that year identifies the economic timing of the project. Sensitivity analysis with respect to the value of customer reliability and cost of the project is performed to confirm the timing of the projects.

For the new zone substation at Templestowe, Nuttall Consulting rates the project as a low probability (33 per cent) of being required. However, the energy at risk justifies that the project must be in service and delivering load by 2016. In order to achieve this, work must be completed in this regulatory period. The project requires purchase of a site and then a two year construction program, a scope of work that and is expected to take more than three years to complete. UED believe Nuttall has erred in this assessment of the timing of this project and confirms that it must be completed within the upcoming regulatory period.

For the Keysborough zone substation, Nuttall Consulting rates the project as a moderate to high (70 per cent) probability of being required, and that there is some potential to optimise the scope. However, UED's planning paper has considered five options and chosen the option with the best net present value. The project must be delivered by 2015 and the project will run over three years, commencing in 2012 in order to meet the time frame. UED believe that Nuttall has erred in this assessment. UED confirms that the project has a moderate to high probability of being required must be completed within the upcoming regulatory period.

For Mentone transformer augmentation, UED agrees with Nuttall Consulting's assessment that the project will be required in this upcoming regulatory period, and confirm that the AER must allow the full amount of the project's estimated cost rather than 90 per cent.

The project to upgrade of the MTS-BW-MTS 66kV line is justified as being part of the most prudent and efficient solution to replacing seriously deteriorated transformers au sub BW. Nuttall has assessed the probability of this project going ahead as moderate (70 per cent). Nuttall's assessment is based on assessment of the remaining life of the transformer. Any analysis of the probability of this project proceeding would require one to opine on the remaining life of the old transformers and the risk and consequence of catastrophic transformer failure if they are not replaced in accordance with independent expert advice. UED contends that Nuttall Consulting has not undertaken this anysis and therefore his conclusion in unreliable.

UED reject this assessment on two accounts. Firstly, UED has developed a proven and practical assessment technique for transformer aging based on condition assessment and transformer performance data whereas Nuttall's assessment is subjective and not based on transformer data. Secondly, a severe overloading of a transformer is likely to result in catastrophic failure and explosion of the transformer and an oil fire which has the capability of destroying the whole substation. UED would breach its obligations under law and the Rules if it accepted such that risks to substation assets, to public safety and UED personnel and the extended loss of customer supplies that would result from such an incident is entirely unacceptable. UED has based its assessment of detailed evaluation of these risks and the poor condition of the transformers and stands by the conclusion, that replacement of these transformers is urgent. Consequently, UED totally rejects Nuttall assessment that expenditure can be delayed.

For the TBTS-DMA-RBD-STO 66kV line upgrade, Nuttall has concluded that UED has not demonstrated that the project is justified on an energy at risk basis, that UED's use of 10 per cent PoE will further delay the project and that alternative, low cost options,, such as an upgrade to the 22kVsystem could be a reasonable alternative which has not been considered. Nuttall concludes that there is only a moderate possibility (70 per cent) of the project proceeding.

A strategic planning paper has been produced by UED to address these concerns. The area served by this loop is one of the most popular summer holiday destinations in Victoria. During the holiday peak time, the population being serviced rises from about 100,000 in early December to nearly 300,000 during January. Correspondingly, load increase markedly with maximum demand almost doubling from early December to the January peak.

There is no doubt that the sub-transmission (66kV) network is well beyond its N-1 planning levels during this time. The N-1 utilisation is estimated to be at 130 per cent in 2010 and 174 per cent in 2015. The load at risk in 2015 is estimated to be 78MVA. At the same time, the heavy load is causing other problems, as the network cannot support the voltage to within the required standards during an outage of the TBTS-DMA sub-transmission line. UED has mandated obligations under its distribution licence to maintain voltage levels within specified levels and must comply with these requirements.

Nuttall has suggested that a cheaper option of providing an additional 22kV line development should be considered. The amount of load to be transferred (78MVA) means that a number of 22kV ties would be required; and because of the length of the ties, a 22kV option will not address the voltage profile problem.

The combination of the voltage and load factors means that the consequences of an outage in a sub-transmission line are severe. UED has concluded that it is imperative for this project to proceed in order to meet the forecast summer loads in the 2011-16 period. UED acknowledges that, because the load at risk only occurs for 5 or 6 weeks per year, the timing of the project could vary, if only the load risk is considered. However, there are other considerations such as voltage profiles and reputational risk, and the alternative to not undertaking the augmentation - to shed large amounts of load during the peak holiday season - is totally unacceptable to UED.

Nuttall Consulting also considered that there is only a moderate probability (60 per cent) that the distribution substation upgrade program is required. Nuttall Consulting appears to have ignored the fact that a business case for this expenditure has been approved by the UED Board and that the program has already commenced. Given the commitment of UED to this project. Nuttall's assessment that this project has only a moderate probability of occurring is totally irrational.

The distribution transformer replacement project also prevents premature aging of transformers and consequential failure due to overheating in periods of high loading caused by overloads. The forecast expenditure is prudent and efficient and part of the long term asset management strategy for distribution transformers.

Nuttall Consulting also claimed that the transformer load management (TLM) system, used to predict overloaded transformers cannot sufficiently identify transformers to be replaced. In fact, transformer loads are measured to confirm their loading before the transformers are replaced.[77] This field experience confirms that the TLM provides reliable data for input into UED's capital planning process - more that 90 per cent accurate in predicting which transformers are overloaded. (and the estimated number of transformers in the program has been reduced by 10 per cent to reflect the field findings

Failure to implement the program will result in failure of transformers with the attendant increase in risk of extended outage times – as demonstrated in the summer of 08/09 – and risks to public safety and public property. In the 2008/09 heatwave, over 40 substations failed in-service with varying degrees of equipment and property damage. In the worst case, a failed distribution transformer caused fire which destroyed a residential home, a garden shed, a side fence and damaged the adjacent home. Such an incident also represents an unacceptable risk of death or injury to the public.

Nuttall Consulting also contends that the 2008-09 heatwave would have identified all overloaded transformers and therefore there is no need for the program to continue. UED contends that such a view is simplistic and incorrect for many reasons. Firstly the heatwave caused rapid ageing of insulation in overloaded transformers. While many overloaded transformers failed at the time, many overloaded transformers did not. However the excessive heat caused acceleration of the transformer insulation thereby causing premature ageing of the transformer. Those transformers remain at risk of prospective early failure with subsequent overloads. Secondly, peak loads continue to grow with further penetration of domestic air-conditioning. Also there are ongoing incidents of customer complaints regarding unacceptable voltage and ongoing fuse operation that requires capital to rectify. Given that distribution transformer loads are not measured in real time, TLM modelling is the only way UED can continue to monitor for overloads.

Given the identified need, the fact that the project is already underway and it has been confirmed that the calculations of loadings are correct and given that the program has UED Board approval, UED cannot accept Nuttall Consulting's assessment of this project.

All the projects reviewed by Nuttall Consulting are well justified, as demonstrated by the strategy planning papers. Their timing has been reviewed and has been confirmed for this revised Regulatory Proposal. These papers are attached as an appendix to this submission. The fact that UED will spend its reinforcement budget allocated in the present regulatory period is an indication the UED's planning procedures provide a reasonable assessment of the required Reinforcement expenditure. UED totally rejects both Nuttall Consulting's conclusion that only 63 per cent of the budget has been justified and the methodology used in arriving at that conclusion.

Nuttall has extrapolated a conclusion from examination of a limited number of of sub-transmission and zone substation programs and applied that to the total reinforcement related capital program. As demonstrated in figure 1 above, the utilisation rate of the distribution network is increasing and 23 per cent of feeders exceed 85 per cent of their

[77] The routine measurement of transformer loading was implemented by UED in the mid-1990s following high profile failures, including loss of power at an AFL football match at the Waverley stadium and a series of failures in former Council assets in the Doncaster and Box Hill supply areas.

thermal rating, a rating at which feeder upgrades generally becomes cost justified. UED has proposed a program costed at $97.6M to augment its distribution network, a number Nuttall has arbitrarily cut based on over-simplified assessment of a limited number of sub-transmission projects. UED rejects this reduction as baseless and without justification. Given that UED has expended its reinforcement allocation in 2006-2010, this Revised Regulatory Proposal confirms that UED's planning methodology has been proved to provide reasonable forecasts of expenditure in the current regulatory period and that provides equally reasonable forecast of expenditure for 2011- 2015.

6.6 Customer initiated capital expenditure

6.6.1 UED's Regulatory Proposal

UED's original Regulatory Proposal explained that Customer Initiated Capital ("CIC") can be further categorised as follows:

- business supply projects;
- urban multiple-occupancy supply;
- urban residential supply;
- customer servicing;
- recoverable works; and
- rural supply.

UED's model for forecasting customer-initiated capital expenditure is based on five components:

- actual expenditure, using data from recently completed projects;
- approved projects, where the customer has accepted UED's offer;
- pending projects, where the customer has not yet confirmed acceptance of UED's offer;
- horizon projects, where only limited details are known at this time; and
- forecast projects (based on historic trends and economic modelling), where the projects have not yet been identified.

UED's original Regulatory Proposal explained that UED's forecast reduction of customer-initiated capital benchmarks for the 2011-2016 period is primarily driven by weaker economic growth forecasts compared to the current regulatory period. In addition, the current regulatory period included the Eastlink Project, which directly added several million dollars to CIC expenditure between 2004 and 2007. In the forthcoming regulatory period, UED noted that several data centre projects could occur and that it was prudent to include an allowance for at least one such project in the forecast CIC capital expenditure.

6.6.2 AER's Draft Decision on customer initiated capital expenditure

UED is please that the AER has determined that the customer initiated capital program provided by UED has been accepted in full. The AER has amended the forecast values based on the application of revised labour and material escalators, but, has made no other changes to the program.

6.6.3 UED's response to the AER's Draft Decision on customer initiated capital expenditure

Consistent with the AER's request to provide more up to date forecast UED engaged NIEIR to provide revised energy and customer number forecasts. This revised forecast has been included as a revision to the customer initiated capital budgeting model. This revised regulatory proposal is based on the most up to date customer number forecasts. The updated NEIIR report has been attached as an appendix to this submission.

6.7 Reliability and quality maintained

6.7.1 UED's Regulatory Proposal

UED's original Regulatory Proposal explained that this category of capital expenditure consists of asset replacement for one of the following reasons:

- Preventative (pro-active): Assets are replaced prior to failure in accordance with life-cycle asset management strategies which have been confirmed as representing good industry practice. For example, asset types showing higher than normal failure rate trends justify an accelerated replacement strategy for the remaining in-service assets of that class prior to their actual failure.
- Reactive: Assets are replaced at the time they actually fail.
- Inspection-based: Assets are inspected based on proven inspection cycles established for each asset class. Assets are replaced after inspection if they meet pre-determined replacement criteria established for that asset class.

UED's original Regulatory Proposal also explained that the current rate of asset renewal is not sufficient to arrest an increase in the average asset age. Evidence, such as the progressive decline in supply reliability (that is clearly linked to increasing rates of asset failure), demonstrates that the current of asset replacement must be increased to ensure the risk of asset base failures is maintained at levels that will be tolerated by customers, and to ensure that the subsequent risk to network reliability return to levels that customers reasonably expect during the 2011-16 period.

UED engaged the services of PB Power to develop a model to test its in-house forecast of replacement capital expenditure. PB Power's model which took account of asset condition information derived from UED's asset management systems, confirmed that UED is entering a period in which the requirement for asset replacement expenditure will substantially increase.

6.7.2 AER's Draft Decision on reliability and quality maintained capital expenditure

The AER stated that it was not satisfied that UED's forecast reasonably reflects the capital expenditure criteria, including the capital expenditure objectives. It also stated that it had specifically taken into account;

- Benchmarked capital expenditure that would be incurred by an efficient DNSP over the regulatory control period.
- The actual and expected capital expenditure of the DNSP during any preceding regulatory control period.

The AER provided specific comments concerning climate change and expenditure on the categories of

- pole top structures,
- zone substations,
- overhead lines replacement and
- reliability

The AER's Consultant, Nuttall Consulting, derived conclusions using an asset replacement model based on age of the equipment which appears to have attributes that are in many aspects to the PB model used by the UED. However, the AER's allowed capital expenditure has been based on historical spending levels with some adjustment to reflect the aging nature of the assets. This places undue weight on only one of the capital expenditure factors and fails to properly address the capital expenditure objectives.

The AER has proposed a regulatory allowance of $140.1 million for RQM capex over the forthcoming regulatory period. UED notes that Nuttall Consulting, the AER's consultant, recommended an allowance of $160.1 million, which compares to UED's initial forecast of $288M. The Draft Decision does not provide any reasons for this further reduction in UED's allowance for RQM capital expenditure.

6.7.3 Historical expenditure.

The analysis undertaken by Nuttall Consulting is based on historical expenditure and it assumes that historical expenditure provides a reasonable basis for predicting future expenditure. UED's methodology for developing RQM capex is more sophisticated and varies depending on the assets type. UED does not use an age based model for some categories of equipment. Model inputs reflect network experience, based on known failure rates or estimated failure rates based on asset condition assessments rather than historic expenditure. Condition assessments vary for asset types, and include non-invasive condition assessment and full condition assessment as appropriate for the particular asset. [Note – please check that suggested drafting is ok]

UED acknowledges that its RDM capital expenditure in the current regulatory period has been lower than forecast. As outlined in section 6.2 above, the regulatory regime (and the discipline imposed on UED by private capital and debt markets) provides very strong incentives to control total capital expenditure within the regulatory allowance. UED's overall capital expenditure forecast for 2006-2010 is only slightly below the regulatory allowance.

Above-allowance expenditure in the Reinforcement and New Customer Connections categories has been offset by a reduction in expenditure in the Reliability and Quality Maintained, Environmental Safety and Legal and IT budgets.

However, UED's network is experiencing deterioration in performance, as evidenced by a trend of increasing SAIDI attributed to an increase in equipment failure rates. At the same time, as outlined in our original Regulatory Proposal, there is a significant increase in the number of assets that are approaching the end of their nominal life. UED has based its forecast expenditure in this category on balanced maintenance and asset replacement strategies, with making a substantial investment to arrest asset deterioration and to improve service reliability.

UED totally rejects the AER's conclusion that historical expenditure levels for RQM capex can be used as a substitute for a coherent asset management framework. If adopted in the Final Determination, the expenditure levels suggested by the AER would be insufficient to meet the needs of the network in the next regulatory period and UED would be forced to make capital rationing decisions that traded customer service standards against ability to cost-effectively access private capital and debt markets. Such an outcome is totally unacceptable to UED.

UED has used a bottom up approach based on coherent, reasonable and prudent asset management systems to develop a forecast of the required RQM expenditure. UED's systems require consideration of the condition of each asset type and, the most practical and cost effective way of estimating the amount of work required to maintain acceptable levels of performance of the network as a whole. UED rejects forecasts based primarily on historical cost basis as these do not account for the changing condition of the assets or changing performance of the network.

A significant proportion of the RQM forecast relates to the replacement strategies for classes of assets of which the population of assets are high ie many tens or hundreds of thousands of asset items. It is impractical to base a forecast on the individual condition of every asset. As an alternative, these high-population classes of assets are modelled. The primary reasons for adopting a modelling approach to the forecast of asset replacement quantities are:

- Alternative forecasting methods such as a forecast based on the condition of individual assets is impractical where asset population is large; and
- An understanding that a forecast of future replacement requirements based on historical volumes is not likely to be accurate.

The PB model uses both age and condition to forecast its volumes. This approach attempts to more closely model the real world where assets are generally replaced based on the condition of the asset, rather than solely on the basis of age. The condition assessment figures included in the model effectively produce a spread of replacement around the nominated asset life for the asset category. The model also has a risk limit. The lower limit sets the level below which the average remaining life of an asset will not be allowed to fall. An upper limit can also be set to avoid over investment or renewing an entire asset type in a short period. The model will force asset replacements to maintain the average remaining life between these limits, thus reducing the average remaining life within these limits.

For other assets, the number and value of the assets, make it practical and cost effective to do extensive condition monitoring to determine life of the condition of the asset. Many items of zone substation plant and equipment are being monitored and the results of this monitoring are used to determine their replacement requirements. Zone substation transformers, switchgear and control and protection equipment fall into this category.

The result of UED's approach is balanced and realistic estimate of the required replacement capital expenditure which identifies increases in some asset types and as decrease in others, based on the age and condition of the equipment. The fact that expenditure on some asset types is increasing and some decreasing is evidence that the methodology is robust and reflects the condition of the assets.

UED's methodology has identified a required increase in replacement expenditure for the following asset types:

- Overhead lines;
- Zone Substations;
- Pole tops; and
- Underground Cables.

And decreases in expenditure for the following asset types:

- Protection and control equipment;
- Network Switchgear;
- Pole replacement; and
- Pole reinforcement.

The PB document "UED Forecast Asset Replacement Volumes" provides further information on the PB model and the inputs that were used in developing estimates for replacement volumes. This document discusses how the inputs to the models used for the 1999, 2004 and 2009 submissions differ and will produce different volumes. The differences are brought about by our better knowledge of the condition of the assets and they are not broadly applied but are tailored to individual assets and result in both increases and decreases in replacement volumes.

For example, the 2009 model will forecast a much smaller volume of assets than the 1999 model due to the input settings for the spread of deferred assets, for a given asset life. Extension in asset lives, based on in-service experience, results in a significant reduction in 2009 when compared with 2004.

6.7.4 Pole Top Structures.

UED's forecasts include an increase in the volume of pole-top structures to be replaced in the 2011 to 2015 period. The reasons for the increase are

- An increasing number of assets have been classified following inspection as being in the "wear out" phase and are failing in service
- A substantial increasing rate of SAIDI caused by asset failure

- Inspections which show an increasing number of pole top structures are in an unsatisfactory condition, and an associated increase in backlog of pole tops that need replacing
- An increasing number of pole fires
- A historical replacement rate that is significantly below the required long term replacement rate.

UED has used the PB model to predict the number of poles that need to be replaced. While age and condition are not exactly correlated in UED's asset condition inspections, there is a strong link between asset age and probability of asset failure for this type of asset. That is, an asset that is older is more likely to have suffered deterioration as a result of prolonged exposure to environmental conditions and therefore is more likely to fail.

An analysis of the age of 4298 cross arms that have been replaced was conducted in 2009. The mean age of the cross arms replaced was 38 years and the standard deviation was 11.5 years, this analysis confirmed (within reasonable statistical criteria) that only 5 per cent of cross arms will last beyond 56 years. Nuttall's report suggests that the sample size is insufficiently large to be considered representative of the average life. This is factually incorrect. The sample size is almost 10 per cent of the population size which is large enough from a statistical point of view for the average life to be calculated with a high degree of certainty.

It is important to understand that the inputs to the PB model are based on the analysis of failed pole top equipment and the input data. That is, the input is not based on assumptions, but of actual observation of pole top top condition. Therefore, the output of the PB model can be relied upon to statistically reliable forecasts that form a basis for reasonable and prudent business planning.

The volume of pole top fires experienced over recent years has had a severe impact on network reliability and a significant operational impact. Pole top fires account for more than 7 per cent of all minutes off supply and they show an increasing trend from approximately 28 per year in 2004 to 75 in 2009. This trend can be directly attributed to deterioration in pole top hardware.

Nuttall Consulting claims that the risks from pole top failures are not new and, as they are being managed with existing expenditure levels, no further increase in expenditure is required. This claim is totally at odds with field data which shows an increasing rate of equipment failure and an increasing number of pole top fires. These observations are consistent with a scenario of aging assets which require additional expenditure if present levels of performance are to be maintained or improved.

The volume of pole top structures proposed in UED's submission for the 2011 to 2015 period will lead to a modest reduction in the volume of assets that have exceeded their nominal life. UED has attached updated planning papers that provide further evidence that this program is necessary in the forcthcoming period.

6.7.4.1 Zone Substation

The zone substation activity code broadly covers the replacement of primary plant within zone substations. A major proportion of this expenditure in the next period is due to the proposed replacement of power transformers and circuit breakers. The recommendation for replacement of all the equipment in this category is based on condition assessment. For all this equipment that is to be replaced, UED engineers have assessed it as being at the end of life within the next regulatory period and that it needs to be replaced. Given that the programs are based on detailed assessment of asset condition and the importance of the assets to the network, UED confirms, that, all identified expenditure is adequately and reasonably justified and critical to satisfactory operation of the network.

Zone substation transformers are vital and costly pieces of plant in a distribution network, and it is not acceptable to allow the risk of failure to become excessive, because a failure will have a severe impact on the business. With probabilistic planning, it is common place for transformers to be run well above their N-1 ratings for short periods. This is because transformers in good condition have a very low probability of failure during short periods of time. However, if a transformer should fail, it will cause major disruptions to the network for an extended period. Immediate problems include a potential non-supply of energy, in particular because the distribution system may not have sufficient capacity to transfer the entire load. If a spare transformer is available, replacement times of more than two weeks will be typical. Order and delivery times for new transformers extend to more than twelve months. Hence the disruption will last for a material length of time.

There is a lesser, but nonetheless real, possibility that a fault will result in a catastrophic failure of the transformer, potentially with an associated explosion and an oil fire. Should this occur there is a potential for additional collateral damage at the substation. It is not unknown for a transformer failure and the associated oil fire to cause the complete destruction of a zone substation. Obviously the more extensive the damage, the longer it will take to re-instate full supply and the more costly the repair. Fires and explosions also provide a risk to UED and public personnel and property.

For all these reasons, UED has rejected a run-to-failure strategy for zone substation transformers; and this is regarded as unacceptable industry practice. On this basis of replacing transformers before failure means that on average, transformers will not remain in service for their full life. To do so would mean that on average half the transformers would fail in service and half would not i.e. P50 given that failure is normally distributed around the mean transformer life.

The AER's consultant, Nuttall Consulting, accepts that many of the transformers proposed for replacement by UED, are in an advanced state of aging, but still concludes they still may have around 5 – 10 years of remaining life. UED can see no reasonable basis for drawing this conclusion and reject the conclusion totally. All transformers proposed for replacement have been subject to extensive testing and analysis of their insulation to determine that the degree of polymerisation (DP) of the winding insulation will be at or below a value of 200 within the next regulatory period. At a DP value of 200, paper insulation has no mechanical strength and any shock to the winding (such as that caused by current flowing to a fault on a distribution feeder) is likely to cause the insulation to fail and the transformer to fault. Distribution feeder faults are quite common occurring on average at a rate of more than one per day across UED's network. The DP 200 value is an internationally recognised figure for end of life of a transformer and has been adopted by UED. Further Nuttall's view of "five to ten years of remaining life" being a reason not to replace transformers infers a view that a P50 approach to in-service catastrophic failure is acceptable; a view that UED strongly rejects.

UED has also received independent advice from Utility Engineering Services that such transformers with low DP values should be replaced which supports UED's proposed main transformer replacement forecast.

UED has recent experience of this exact mode of failure. A transformer at sub EP failed due to winding insulation failure for a fault on a feeder just outside the substation. For this particular transformer insulation DP value was measured at 400, indicating the end of life figure of 200 is far from conservative.

Aging transformers can sometimes be replaced under the reinforcement allowance if an end of life transformer is replaced with a larger one because it is required to provide load growth. In the regulatory period 2005-2010, there were nine aged transformers replaced, eight of them under the reinforcement allowance. The replacement of these transformers under the reinforcement allowance has provided a skewed impression of the amount of historical expenditure for this category.

Likewise all the zone substation circuit breakers forecast for replacement in the next regulatory period have been subject to a rigorous asset assessment by UED engineers and determined to be at end of life. The replacement criteria are based on a range of factors including failures, defect history, maintenance costs, availability of spare parts and consequences of failure.

The proposed circuit breaker replacement volumes are in line with current levels and are fully justified. A discussion of the circuit breaker replacement strategy is provided in the Asset Strategy planning paper "UED Zone Substation Circuit Breaker Replacements". UED has attached updated planning papers that provide further evidence that this program is necessary in the forcthcoming period.

6.7.4.2 Overhead Line Replacement

The overhead replacement category shows a large increase in expenditure, but from an extremely low base, and the total cost of the program is small when compared to the value of the assets. The quantum of the replacement volumes has been estimated from the PB model for asset replacement and the inputs to the model are based on the age and condition assessment.

The PB model predicts an increasing expenditure in this category. The level of expenditure has been confirmed through inspection of the overhead conductors. UED now uses three methods of inspecting overhead conductors. The first two are long-standing programs and the third recently introduced and has commenced in response to the identified risk.

- Pole and line inspection;
- Thermo graphic surveys; and
- Detailed inspection of defined segments of overhead conductor.

In particular, the detailed inspection of overhead conductors, performed using a pole mounted camera has detected conductors in very poor condition or that have been severely damaged where this is not visible from the ground.

The AER's consultant, Nuttall Consulting, considered that there was insufficient evidence to justify the scale of the increase for this category of assets. UED has provided additional information in the following documents:

- UED Forecast Asset Replacement Volumes (PB); and
- Asset Strategy Planning Paper – Overhead Conductor Replacement Program.

There is considerable evidence to support an increase in the volume of overhead conductor replacement. The proposed replacement rates are not excessive and do not result in a reduction in the proportion of conductors that are older than their nominal life. The program is required if network performance levels are to be maintained. UED has attached updated planning papers that provide further evidence that this program is necessary in the forcthcoming period.

6.7.4.3 Reliability maintained

The reliability maintained category of the budget includes a list of programs to improve the performance of the network. Two of the larger projects are for the installation of high voltage aerial bundle cable and the installation of harmonic filters.

The high voltage aerial bundled cable (ABC) program has been proposed in response to the deterioration of performance of the network. Whether the deterioration is due to climate change or not, the fact is that network performance, as indicated by SAIDI is deteriorating at a rate of 6.5 minutes per year. The strategic use of ABC conductors in some areas is one of the proposed methods of stabilising and reversing this trend.

This category also includes provision for capital expenditure for the installation of harmonic filters for power quality reasons. UED are required under their licence conditions to meet certain requirements for harmonics on the network. On the HV network, total harmonic distortion (THD) level of less than 3 per cent is required. Presently there are more than 19 zone substations on the network with THD above this level. The affect of harmonics is to affect the operation of equipment on the network. Harmonics has also caused a number of failures of equipment, particularly for capacitor banks.

The program proposed for the 2011 -2015 period includes provision of harmonic filters in the 10 worst performing substation so that customers are supplied within the required power quality limits. In addition harmonic tuning reactors are planned for 8 capacitor bank to address equipment failure issues.

The program for harmonic filters and tuning reactors are required and justified to meet the requirements of the distribution licence. UED has attached updated planning papers that provide further evidence that this program is necessary in the forcthcoming period.

6.7.5 Comments on Nuttall's Methodology on RQM Expenditure

In its review of UED's RQM capital expenditure, Nuttal Consulting developed an alternative Replacement Model (REPEX) and also provided an analysis of the historical trends of the electricity businesses. Nuttal Consulting's conclusions were based on the output from it's REPEX model and the trend analysis. UED provides the following comments on Nuttall's work.

Nuttall REPEX Model:

Nuttall Consulting has developed a replacement model (REPEX model) to support the review of the DNSP's capital proposals. The model uses age as a proxy for the many factors that drive individual asset replacement. In developing the model, Nuttall has assumed that the recent historical replacement levels are reflective of a prudent and efficient management of the asset base.

It is worth noting that Nuttall has benchmarked expenditure of the Victorian DNSPs against interstate electricity utilities in New South Wales and Queensland and comparisons demonstrate that the Victorian DNSP's are significantly more efficient in their capital expenditure when considering expenditure against asset base value, line length, number of customers, energy distributed and peak demand.

Nuttall Consulting does not provide any analysis to demonstrate that the Victorian DNSP's historic expenditure is sufficient to maintain current network performance. For example, benchmarks in trends for average asset lives, network reliability and equipment failure rates could have been used to form an opinion of the prudency of the proposed capital programs. Instead, Nuttall assumes that the historical level of spend because it addresses past network risks, is sufficient to address simular risks in the future, in spite of the fact that present expenditure levels are resulting in increases in asset age, and increasing equipment failure rate and a reduction in network reliability. UED assert this assumption is fundamentally incorrect and without basis.

Similar to Nuttall, UED uses its own age-based model produced by PB to develop its estimate for replacement capital spending. By using actual age, condition and performance data, this model is far more accurate in predicting future asset condition, performance and risk and the level of expenditure required to prudently operate the network. Nuttall points out that this model predicts a large increase in capital expenditure over historical amounts and argues that historical expenditure is a better predictor of future spend.

Hence, Nuttall has calibrated his REPEX model against historical volumes and expenditure for historical years 2006-2008. His model assumes a normal distribution of the lives of various assets and he has adjusted (or "calibrated") the lives so that the model corresponds to correct historical expenditure. Unsurprisingly, the model then recommends that the present trend of slowly increasing replacement expenditure is continued, which reflects the historical trend. This is an extraordinary approach where the forecasting model has been designed to deliver a desired result; an approach which UED strenuously rejects as entirely inconsistent with good industry practice and good principles of asset management.

Whereas UED believes that an aged based model has merit in predicting future expenditure, the sole use of historical expenditure to determine the future expenditure is fundamentally unsound and imprudent for the following reasons:

1. Use of 2006-2008 expenditure and 2004-2008 replacement volumes has biased the result on the low side;
2. It results in a wide disparity of predicted asset lives between businesses; and
3. The asset lives which are fundamental to predicted expenditure are not related to actual assessment of asset lives based on observation and evidence based condition assessment.
4. The Nuttall REPEX Model selectively uses the annual average annual historical replacement volumes for 2004-2008 and expenditure activity in 2006-2008 for "cali"ratino". By not including the estimated figures for the calendar years of 2009 and 2010, the model has been biased as the expenditure on RQM in these years is significantly higher than for 2006-2008. The actual expenditure for the years is now available for 2009 and updated estimates, including actual expenditure to date, is available for 2010. This information confirms that the expenditure is in line with UED estimates. This simple change means that Nuttall's REPEX model underestimates the cost of replacement by some $46 million.

All assets installed before 1995, were all installed by either, the State Electricity Commission of Victoria or one of eleven local municipal councils In UED's case the local municipal councils of Box Hill and Doncaster/Templestowe were amalgamated with SECV distribution networks. An observation from Nuttall's weighted average life calculations of the various assets demonstrates a large variance in weighted average life for the same asset classes between businesses. In general, Nuttall's spread of asset lives is much larger than that in the data provided by the distribution businesses and with nine out of the 11 asset categories, the Nuttall model produces a greater spread of ages.

This is a strong indication that the Nuttall's method of re-setting the life on an asset based on asset replacement expenditure is over simplistic and flawed. Extreme cases are in the areas of service lines and underground cables. For both categories, there is a variation of asset lives of more than 200 per cent between businesses according to Nuttall's model. The large variation between various asset types calls into question the assumptions that have been made in developing the model, and, in particular how the model has been calibrated.

UED believes that a validly developed model would produce a similar estimate of life for similar assets across all the distribution business and if failure to achieve this is an indication that the model cannot be relied on to accurately forecast expenditure. UED accepts that there will be some variation to asset lives due to different growth profiles of individual parts of Victoria, however variance should not be at the magnitude of 200 per cent. These large variances are not explained by Nuttall and in UED's opinion are evidence that the model is not adequate for assessing UED's forecast expenditure.

UED determines the useful life of network assets industry-accepted standards and based on:

- Manufactures' recommendation;
- Past experience on our own network;
- Inspections and asset assessment; and
- Industry benchmarks.

Asset lives have been benchmarked against industry standards to confirm their validity. However, for many of the assets classes we are, for the first time, approaching the end of their predicted lives. There is some uncertainty about when the end of asset lives will occur but if it is assumed that the lives follow a normal distribution curve, it is expected that sixty seven percent of the asset failures will occur within one standard deviation of the mean life. A prudent network operator will use the best available information to assess the optimum time to replace an asset. For some assets, it will be acceptable to replace on failure, and an asset life model is appropriate to determine the capital expenditure required.

The asset lives used in the Nuttall Consulting model are not in accordance with and, for most classes of assets, have been extended well beyond industry benchmarks. Industry benchmarks for asset lives bring together the wealth of experience across a number of businesses and are accepted by regulators as an indicator of prudent practices good governance. Nuttall's asset lives which have been developed from past expenditure levels do not reflect industry experience and, unlike the lives used by UED, have no technical basis.

However, Nuttall has not used his REPEX model to estimate the expenditure for UED, but has instead used two types of asset cost information.

Where UED's estimated expenditure is less than historical levels, Nuttall has used the UED levels. But, where UED estimated expenditure for an asset type is more than historical levels, Nuttall has used historical levels adjusted for age, with the age factor calculated from the REPEX model. This demonstrates a bias that is totally unreasonable and totally inconsistent with any reasonable interpretation of the Rules applying to AER's functions

UED cannot accept Nuttal Consulting's forecasting methodology or its reliance on historical expenditure, which has been accepted by the AER. As discussed, because the model does not include expenditure for years 2009 and 2010, and because there was significant increase in RQM capex in those years, the model does not reflect historic expenditure.

In addition, UED is of the view that the model is fundamentally incorrect because it makes a number of assumptions which are not valid and because it encourages inefficient behaviour. These are:

1. It assumes no change in the assets condition, their physical environments and obligations of the businesses between regulatory periods.
2. It cannot address emerging issues or evidence from test results or trends that become apparent during a regulatory period.
3. Some assets classes are relatively new and practically no historical replacement has been undertaken,
4. It rewards over-expenditure and inefficient behaviours.

No change in assets condition:

By using historical data to predict future spend Nuttall assumes that the condition of the assets remains constant, resulting in similar failure rates and replacement rates from one period to the next. Nuttall also assumes that the present level of expenditure is sufficient to maintain the assets in a constant condition. In fact, the evidence presented by UED shows that failure rates are increasing and reliability indices deteriorating. By providing a similar level of funding to the previous period these trends could have not been reversed and performance of the network would continue to decline.

The assets are also aging. From 1960, there was a significant expansion of the UED electricity region and about 20 per cent of the assets were installed between 1960 and 1970. This compares with less that 10 per cent of the assets being installed before 1960. These assets are approaching the end of their life for the first time. We expect an increase in failure rates but this increase would not have been seen in the present regulatory cycle. As a result Nuttall's model fails to predict this increase in expenditure. We have estimated that expenditure less that about $55 million per year will result in long term aging of the network and that our current proposed reliability and quality maintained budget aims at only maintaining the present average age of assets.

In addition, it is generally accepted that climate change has begun and, although the effects of change may be gradual, CSIRO modelling predicts that higher wind speed will occur, and high wind speed events occur more frequently and higher extreme temperature events occur and high temperature event occur more frequently. These impacts combined with aging assets, are certain to cause more failures on the network. It is necessary to replace aging assets in order to make the network more robust to withstand the expected worsening climate conditions.

Emerging Issues

Nuttall's model requires past expenditure in order to justify future expenditure. If emerging issues occur, for example from test results or trends, then the model does not have a mechanism to provide for an increase in expenditure. Using Nuttall's model, one could not conclude that an increase in expenditure without assuming that similar expenditure was incurred in the preceding regulatory period.

Best practice asset management is to replace plant and equipment before it fails and with Nuttall's method funding for replacements cannot be obtained before it occurs. Expenditure for replacement of important items of plant such as transformers and circuit breakers, whose in-service failure can cause significant disruption to the network and customer supply, cannot be justified (in Nuttall's model) until failure occurs. This is not consistent with prudent operation of the network as it would result in unacceptable supply risk and health and safety risk for the business.

The increases in the proposed replacement capital expenditure are, in fact, largely due to the identification of a number of emerging issues such as:

- Pole top replacements;
- Switchgear replacement;
- Zone substation transformer replacement; and
- HV ABC conductors.

If justification of an increase in expenditure is based on historical expenditure then, for future price review periods, increases will only be granted post event; that is, we would need to increase expenditure in the current period in order to get an increase in future periods. A good example of this is UED intended replacement of substation transformers which are at end of life, but for which the AER has rejected additional expenditure.

Hence, the effect of the model will be to increase asset lives and reduce replacement funding until an asset fails and then provide funding in the next period for its replacement when it may not be needed. In Nuttall's model funding is based on work that has occurred rather than work that is required.

Reward for Over-expenditure.

By being based on historical expenditure, the Nuttall model rewards poor asset management and inefficient practices. Those businesses which historically are shown to be less efficient will continue to be provided with additional funds whereas efficient network businesses will not be. This will encourage long term increase in expenditure. It should be noted that UED has not asked for long term continual increases in reinforcement capex. In fact, UED's submission predicts that it will decrease in the final two years of the 2011-2015 review period.

Comments on Asset Life

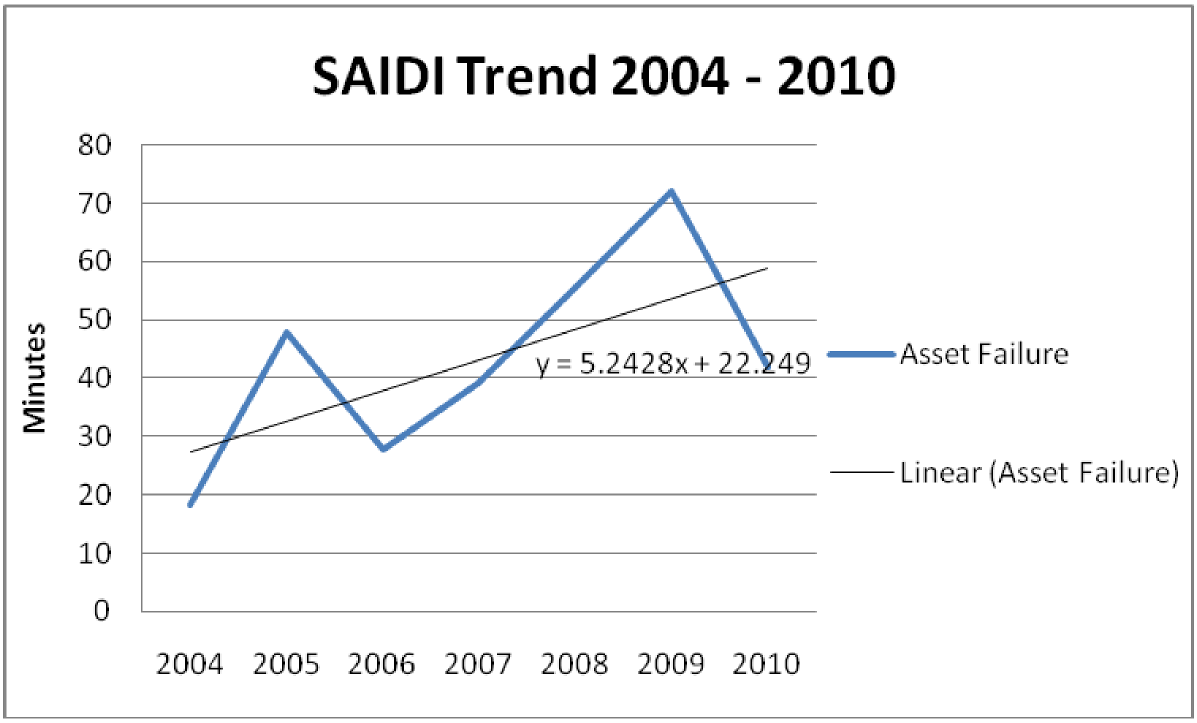
There was a significant expansion of the electricity network in UED area during the 1960's. For example, approximately 20 per cent of the network assets were installed between 1960 and 1970. In comparison, less that 10 per cent of the asset were installed before 1960. Based on UED's life cycle management plans, the average life of UED's assets has been estimated at 51 years, and hence a significant proportion of new assets will be reaching the end of the life in the regulatory period from 2011-15. UED agrees that age is only a proxy as a replacement indicator but for the purpose of the model, it is an indicator of an expected increase in expenditure particularly for classes of assets where the management strategy is to run to failure.

Key to the difference in replacement capital expenditure predicted by the Nuttall and UED REPEX models is the assumed of asset lives. Nuttall has used past expenditure levels to calculate lives and calibrate his model. UED's experience is, that although past expenditure may be an indicator of future spends, it is not necessarily so and is not a sufficiently robust assumption to adopt when developing an expenditure model.

It is noted that Nuttall's model has effectively increased the average life of assets by eight years thereby deferring much of the age-related capital expenditure to the next regulatory period. Nuttall argues that replacement models indicate a "bow wave" of expenditure i.e. a peak in year one which gradually reduces. He argues that this would occur if the lives of assets in the model are too long allowing actual expenditure to lag that predicted by the model. On face value this argument has some merit. However, there are other indicators that demonstrate that present level of expenditure will not be sufficient for the future. For example, over the last regulatory period, there has been a marked increase in equipment failures resulting in an increase in reliability indices. This risk has been managed through various reliability programs which were implemented over the last period, thereby masking the affects of Nuttall's predicted "bow wave": That is, the reliability programs have allowed deferral of replacement expenditure. UED believes that this has been efficient and prudent practice but there is less scope for reliability programs to manage these risks on the forthcoming regulatory period.

It is to be expected that historical levels of expenditure will result in historical trends and levels of performance. This trend is one of deteriorating performance and increasing age of assets. We can demonstrate that the deterioration in performance of 5.2 customer minutes will occur just for asset failures over the regulatory period and without an increase in replacement capital expenditure is required to address this issue.

Figure 6-5: SAIDI Trend 2004 - 2010



The above graph indicates a trend of deteriorating performance caused by asset failures. UED are expecting this trend to further deteriorate as an increasing proportion of assets are approaching their nominal end of life.

UED's Asset Management Plan has demonstrated the effect on the network of maintaining levels of expenditure. It shows that the average remaining life of the assets will decrease from approximately 48 per cent to 40 per cent over the next ten years if the current levels of expenditure are maintained.

Changes to the Physical Environment.

UED has made allowance in its original Regulatory Proposal to cater for the effects of climate change. Nuttall's model makes no allowance for changes in the physical environment and assumes climate conditions remain constant (or that future climatic conditions can be represented by the full historical climate data set) and the physical environment in which UED's network will operate is constant. The fact is that the performance of equipment is deteriorating indicating that it is failing to deal with the environment. Where this is due to a worsening physical environment brought about by climate change, or whether it is due to deteriorating equipment is a moot point because the solution to both problems is to increase on RQM capital expenditure.

6.8 Environmental, safety and legal

6.8.1 UED's Regulatory Proposal

UED's original Regulatory Proposal explained that this category of capital expenditure must:

- enable UED to comply with all applicable laws and regulations;

- safeguard the environment for communities within which UED operates through prevention of adverse environmental impact and the considered risk management of all activities;
- continuously improve the Environment Management System;
- achieve and maintain certification to ISO 14001;
- identify innovative environmental solutions for services delivered;
- ensure that all significant environmental hazards and risks are identified, assessed and controlled; and
- ensure employees and contractors understand their responsibility for the environmental performance of their activities.

UED's original Regulatory Proposal explained that UED forecasts an increasing spend profile in this category, principally as a result of the following two projects identified in the AMP:

- The replacement of neutral-screened overhead services. Neutral screen services are known to have a failure mode that can result in minor or in some rare cases major electrical shock to the public. UED records about 150 minor electrocutions to customers and members of the public per annum; 80 percent of these being caused by failures of this type of neutral-screened service cable. .Originally a 10-year replacement program of this cable type was planned. To better manage this public safety risk, a five-year program is now proposed to replace the total population of this service cable type. This program has been included in UED's Safety Case submission to ESV. UED's initial feedback from ESV is that in considering UED's Safety Case, ESV will approve the replacement of this class of asset over seven years considering it as being an appropriate risk-based response to a public safety issue. ESV has also stated (at the AER/ESV/DNSP meeting 14th July 2010) that DNSPs will be obliged to undertake all the programs included in their approved Safety Cases and is subject to ESV audit. On this basis UED will be obliged to undertake this program.
- The installation of ground fault neutralisers ("GFN") in zone substations that serve high bushfire risk areas. A GFN has been installed in Frankston South zone substation and its in-service performance in reducing fault energy and reducing voltage quality dips has been excellent. The further installation of GFNs will serve to materially reduce the risk of fire starts in UED's fire risk areas. Similar to neutral-screen cables, the GFNs have been included in UED's Safety Case and as such if approved, will be an obligation to deliver and subject to ESV audit.

6.8.2 AER's Draft Decision on environmental, safety and legal capital expenditure

UED proposed a total expenditure of $51.1M for the category of Environmental, Safety and Legal (ES& L) for the period 2011 to 2015. The AER's conclusion was to allow $42.7M for the same period which is in line with historical expenditure.

The AER considered that UED

- Has not adequately demonstrated the underlying need for a step change in expenditure

- Has not demonstrated the economic justification of the projects
- Has not demonstrated why they cannot manage existing program and associated risks within the current levels of expenditure.
- Has not quantified the benefits and outcomes to customers
- Has not demonstrated how the application of risk management practices and procedures set out in the risk assessments translated into forecast expenditures.

6.8.3 UED's response to the AER's Draft Decision on environmental, safety and legal capital expenditure

As discussed above, the increasing trend in this category of expenditure is the result of increasing expenditure on two projects – the replacement of neutral screened overhead services and the installation of ground fault neutralisers. The AER's consultant, Nuttall, has identified that the neutral screened services program was originally a ten year program and has been has been brought forward to be completed in seven years, within the 2011-2016 regulatory period. Nuttall believes that UED has not demonstrated any change in regulation or business driver that suggests that the neutral screened replacement program should be materially different from currently adopted practices.

The driver for the change of approach for the neutral screen services replacement program are twofold. Firstly, on the legislative side, new Electricity Safety (Management) Regulations were introduced in 2009 and amendments were made to the Electricity Safety Act 2007 which came into affect on 1 January 2010. The new regulations allow a robust risk management process to manage its network safety based on risk. The ESV has identified a number of principal risks:

- Unsafe connection to customer premises
- Pole fires that can be cause of distribution lines falling
- Defective and degraded earthing systems
- Low power lines
- Flash burns and electrical shocks
- Supply network faults causing unsafe situations in customer installations
- Maintenance problems in respect of ageing supply assets
- Structural fires

With respect to the neutral screen service replacement, UED started a 10 year replacement program in 2008 due to an observed increasing trend of failures of this class of services and the resulting public safety hazard.

Secondly, following a formal risk assessment workshop, the potential of severe risks such as customer fatality were identified. The only realistic option to address the risk is to eliminate it by replacing this type of overhead service. Risks have been assessed as so severe that the program is to be accelerated so that it is completed by 2015.

UED believe that following the risk assessment process, we can no longer manage the risk with a ten year replacement program. By accelerating the program UED will be managing the risk in accordance with the requirements of the ESMS

The installation of ground fault neutralisers is another program that has been identified in the ESMS to improve public safety by

- Reducing high voltage injections,
- Reducing step and touch potential on conductive structures,
- Reducing bushfire starts.

The economic justification for this project is based on the cost to the community of bushfires. The AER's consultant, Nuttall has erroneously concluded that UED does not required funding for this project based on its internal benefits and states that the costs can be fully recovered by UED. This is not the case as the savings identified are community savings and UED required capex funding for the project.

Nuttall also argues that the reduction in fire risk has not been adequately quantified. UED has prepared a strategy planning paper – UED 2010 – GFN & SWER- which identifies 99.6 per cent reduction in fault energy for phase to ground faults and is provided along with other documentation in support of this report.

In summary, UED are proposing an increase in their ES&L budget to meet new requirements and obligations under the new ESMS regulations. These requirements are partly directly due to the new regulations, and partly due to the re-evaluation of risks. The programs have been developed following a detailed and formal risk assessment process and are well justified and technically sound. By reducing the funding on ES&L category, UED will be unable to meet its requirements under the ESMS. UED assert that the capex proposed under its submission is the minimum required to meet its allegations. UED has attached a number of specific life cycle asset management plans that provide the AER with further substantiation of these safety related programs.

6.9 SCADA and network control

6.9.1 UED's Regulatory Proposal

UED's original Regulatory Proposal explained that its forecast for this category of capital expenditure reflects UED's proposed relocation of the control room. Currently UED's control room functions are managed by JAM. UED explained that the in-sourcing of the control room function and the relocation of the control room into UED's facilities is consistent with its intended transformed business model; this model being typical of best-practice power distribution utilities where the asset management functions and network operational central control are co-located.

6.9.2 AER's Draft Decision on SCADA and network control capital expenditure

The AER has rejected UED's total forecast for SCADA on the basis that UED has not demonstrated that alternative arrangements necessitating the in-sourcing of control functions will be in place in the forthcoming regulatory control period.

6.9.3 UED's response to the AER's Draft Decision on SCADA and network control capital expenditure

UED's original proposal and this revised proposal is made up of two separate components for SCADA. These being

- Control Room relocation; and
- Increasing data centre fibre capacity

These are two very separate projects within these categories. The AER has failed to consider the data centre fibre capacity as its own discrete project as this is not mentioned in the analysis. UED directs the AER to consider this project on its own merits and separates it out from the relocation.

In terms of the control centre project UED provided the AER with substantial substantiation of the business transformation project. A critical component of the transformation includes the bringing in-house of core asset management and network operations control functions back in-house. This by necessity includes the creation of a network control centre within UED-managed premises.

UED is the only Victorian distributor to not own and operate its own Network Control Centre. UED has informed the AER that it intends to in-source a number of critical and core functions as part of it revised operating model. Distribution network operations control forms a core part of this strategy. UED therefore needs a control centre facility to operate this core service.

Without a fully functional control room UED is unable to bring these services in-house. It should be noted that no service provider offered such a facility through UED's tender process. There is no certainty that UED can rent or obtain access to a suitable third-party facility as there is no market for such a facility provision.

UED simply cannot tolerate the risk of not having continuous access to a suitable control facility. On this basis UED has already commence planning for the commercial lease of property and the construction of a new network control centre. The AER's rejection of UED's proposal to create such control centre facility would leave UED as the only Australian DNSP without its own control centre and with the risk of being unable to operate its network and meet its licence obligations.

6.10 Non-network assets - IT

6.10.1 UED's Regulatory Proposal

UED's original Regulatory Proposal explained that recent low levels of IT expenditure have resulted in a number of capabilities being absent from or inadequate in UED's IT environment and as such has increased UED's commercial and technical risks. UED IT program for the forthcoming regulatory period sets out a roadmap that lays the foundation for an effective and efficient IT capability aligned to UED's business needs.

UED's original Regulatory Proposal recognised that its proposed IT capital expenditure is a significant increase compared to the current regulatory period for the following reasons:

- IT systems are "end of life" and therefore require significant cost to maintain and manage.
- UED's business requirements are changing requiring IT systems to support multiple contracts; meet changing regulatory obligations; manage increasing data; manage increasing customer expectations; and achieve the efficiencies forecast in the operating budgets for IT and network related costs.

UED's original Regulatory Proposal identified a total of 47 projects (including minor business change requests) with 28 projects within the forthcoming regulatory period.

6.10.2 UED's understanding of the AER's draft determination

UED has reviewed the Non-network–IT capex findings from the AER's draft determination and understands that the AER has accepted the recommendation of Nuttall Consulting that:

> *"the capex amount proposed by United Energy for 2011–2013 has been spread evenly across 2011–2015"*

The AER's draft decision model does not reflect this statement. UED assumes that the AER has made an error and would seek to redress the situation in the final decision. Table 8.53 within the draft decision is simply UED's total forecast with a different timing rather than the Nuttall recommendation. UED interprets the AER's draft decision as recommending an IT Capital allowance of $75.6m plus an appropriate labour and material escalator to be spread over the five year period which equates to an annual allowance of $15.1m per year (plus the labour and material escalator).

6.10.3 UED's response to the AER's draft determination

UED maintains its position that the IT Strategy developed and presented to the AER was and still is a prudent and efficient way to manage a complex, dynamic and challenging area of the business.

UED used a structured approach to develop the IT Strategy that takes into account inputs from the business, the state of the current IT environment and emerging IT trends to develop an IT roadmap that delivers the necessary IT systems to support the business objectives.

UED has reassessed some aspects of the IT Strategy in light of the recommendations made by Nuttall Consulting and the AER's draft determination. In particular, UED has assessed its ability to implement the Strategy, the accuracy of the cost estimates and the mix of capex / opex.

Further details of UED's response are set out in the following sections.

6.10.4 Ability to implement the Strategy

UED accepts that the IT Strategy and Delivery program is large in comparison to previous years and presents a delivery challenge for UED over the next 5 years. UED has assessed its own ability to implement and deliver the necessary changes and believes that it is capable of delivering the program in full. The board has signed off the deliverability component of the RIN and regulatory sign off in its original submission. UED's management and board assessed the full IT program at that stage and committed to signing the certification on the basis that it could deliver the program. Nothing has come to UED's attention to suggest UED is unable to deliver the full program. Indeed, since the submission UED has put into place delivery programs and governance structures that will assist the completion of the full program.

In addition recent outcomes from arbitration make the IT program more deliverable with the ability to choose from a wider range of service providers in implementing the programs. The AER cannot simply dismiss the IT program on the basis that the Nuttall Consulting group believes the program is large and there is a possibility that the 40 per cent of the program can be deferred.

The AER's simplistic approach to revising forecasts fails to recognise important strategic projects in the final two years of the project that must be completed in order to achieve the efficiency savings identified in UED's operating expenditure forecast. For example there are three critical projects that must proceed, these are identified below:

- **GIS upgrade** – Upgrade to the GE Small world application in line with good lifecycle management practices. This system forms a core system within the UED application architecture. It is integrated with the OMS / DMS system and the core ERP system and therefore plays an important part in supporting asset and network management business processes
- **DMS upgrade** – Upgrade to the Oracle NMS application which will have been implemented into the UED environment for over 7 years at the time of the planned upgrade. This system is a core network control system which allows UED to meet its market obligations and targets (e.g. SAIDI, SAIFI).
- **CIS Type 1-4 consolidation** – Consolidation of Type 1 – 4 meters from the legacy CIS system into an alternative solution (e.g. outsourced service or SAP IS-U). This project is scheduled to be completed after all AMI meters have been deployed and therefore is required so that the CIS system can be decommissioned.

6.10.5 Accuracy of the cost estimates

Since completing the IT Strategic Review in late 2009, UED has continued to refine the cost estimates associated with key projects such as the ERP – SAP Consolidation. Accenture were recently engaged by UED to assist in developing a detailed business operating model as an initial phase of the ERP – SAP consolidation project.

The outcome of this project was a recommendation from Accenture that the future ERP – SAP Consolidation project be split into three phases to be delivered in sequence.

- Phase 1 – a tactical implementation based on the legacy SAP 4.6c system that allows UED to meet the business transformation objectives.
- Phase 2 – a consolidation project which will consolidate the legacy SAP 4.6c implementation onto the AMI SAP platform. Additional SAP modules that were not implemented on the AMI SAP IS-U platform will be enabled as part of this project.
- Phase 3 – a strategic project which will provide increased business benefit to UED through the deployment of SAP based portal and business intelligence capabilities.

Phase 1 of the project has just received UED board approval, with phase one beginning in August 2010 and being completed by April 2011. The AER is required to recognise the updated forecast for this project on the basis that this is now the best available data. Attached is the Accenture report detailing the forecast of all three stages of the project. This project is a key plank in UED's revised business operating model and essential for UED to deliver business benefits such as regulatory reporting. The AER's draft decision has already "approved" the programs in the first three years of the regulatory period. This submission now provides an updated forecast which is consistent with the AER's approach to update forecasts with the best available data.

Details of the Accenture approach, the cost estimates, cost methodology and timeframes are provided as supplementary evidence to support this response.

6.10.6 Mix of Capex / Opex

The IT capex projects proposed in the IT Strategic review have a direct impact on the IT operating costs proposed in UED's original Regulatory Proposal. UED's proposed IT strategy seeks to reduce the total number of IT applications in use at UED. This reduces the ongoing operating costs to support these applications.

For example, the delivery of the system consolidation and rationalisation project has a direct impact on the support, maintenance and infrastructure costs. These reductions were accounted for in the operating costs proposed in the original Regulatory Proposal.

UED's IT operating costs fall over the five year regulatory period as a direct result of the delivery of the IT capex projects. UED is the only Victorian Distribution business to provide a declining cost profile. A reduction in the capex allowance for IT projects will have an impact on the operating costs for IT.

UED recognises that the AER and Nuttall Consulting have identified a lack of agility in IT infrastructure across all Victorian DNSP's and recommend using infrastructure service based offerings to improve the ability to change rapidly. UED has assessed this position and has provided a detailed response to this position later in this chapter.

6.10.7 How does the UED IT Strategy process work?

As discussed with the AER in the draft determination process, UED uses a gradual decision making process to move from IT Strategy to IT Architecture and eventually project delivery.

The IT Strategy outlines the program of work to be completed over a five year period to align with the business requirements and strategy. In essence this document defines a series of functional projects (e.g. Implement new Content Management System, Upgrade Distribution Management System) that need to be completed over the period in a sequence that takes into account "do-ability" and the dependencies that exist between projects.

The IT Strategy and Roadmap that was provided to the AER during the draft determination process highlighted this approach and whilst ambitious in nature, it did reflect a balanced program over the five years to meet the requirements of the business.

Each year, after the IT Strategy has been endorsed, the portfolio of projects for that year are analysed at a more detailed level. The technical solution/s are defined at a high level and tested against a series of guiding principles including alignment with business objectives, managing risk, technical dependencies and constraints. At the completion of this assessment the business case is then developed which will at that time include cost/benefit analysis and any other economic justifications for the proposed project/s. In the case of major projects (>$1m) board approval then completes the governance process ahead of project delivery commencing.

6.10.8 What principles are used to direct the IT investment?

As noted above, UED uses a number of guiding principles to direct IT investment decisions, these include:

- **Buy not build** – UED does not consider itself to be an IT development organisation and therefore all projects need to have a bias towards purchasing 'Commercial off the Shelf' software as opposed to developing applications internally;
- **Security and control** – UED recognises the critical nature of electricity infrastructure and is focused on development of secure IT systems that are implemented in accordance with good industry practice. As an example, UED have recently been certified for the AMI systems as being ISO 27001 compliant. UED aims to extend the compliance across all non-AMI systems in the near future. Security is a high priority for UED;
- **Own not lease IT assets** – UED recognises that all IT environments contain a mix of owned and leased assets. However, UED's preference is to own assets as this provides an increased level of security and control over leased assets;
- **Virtualise, when appropriate** – UED supports the use of virtualisation technologies within the current environment. However, not all applications or infrastructure services are recommended for virtualisation and therefore UED considers that a "case by case" assessment of virtualisation candidates is a prudent course of action;
- **Consolidate, when appropriate –** UED supports the use of consolidation across applications and infrastructure to lower the total cost of operating IT systems. However, consolidation should be assessed on a case by case basis to ensure that UED does not suffer from an architecture that places "all the eggs in one basket";
- **Outsource commodity, insource strategic** – UED believes that as the IT market has matured, a number of IT services have become commodity services. These services are prime candidates for outsourcing which has been reflected in our UED's operating expenditure forecasts. However, strategic functions (e.g. IT architecture, project delivery) help UED to meet its business vision and should be therefore retained in-house. These strategic functions have therefore been targeted for in-sourcing from the current service provider;
- **Evolution not revolution** – UED believes that the current systems deployed into the IT environment (e.g. SAP, WebMethods, Oracle NMS, GE Smallworld) are some of the leading IT products in their functional areas and therefore favour evolution of these product sets as opposed to revolution (e.g. replacing SAP for a 'best of breed' ERP architecture);
- **Mature products over 'bleeding' edge** – UED recognises that IT plays a significant role in enabling the business vision and creating opportunities for innovation. However, in choosing technologies, services and methodologies, UED believes that

a prudent approach is always to favour mature products over 'bleeding edge' products;

- **Flexible architecture over stovepipe** – UED believes that all IT architecture should be designed according to flexible, modular and decoupled architecture techniques (e.g. design patterns, separation of application and data tiers). Projects are assessed against this principle to ensure that the architecture being deployed is able to meet future needs; and

- **Open not proprietary standards –** UED is committed to using open standards across the IT environment and reduce the reliance on vendor specific proprietary standards. Open standards increase the flexibility of system integration and reduce the danger of products becoming redundant.

In certain cases principles may conflict with one another (e.g. security vs. flexibility). When principles conflict a business decision will be made on which principle is of higher importance.

6.10.9 Does UED have an agile and flexible IT Architecture?

In answering this question, UED has reviewed the AER's Draft Decision and the supporting report from Nuttall Consulting in order to understand why the AER does not consider UED to have an agile and flexible IT architecture. UED is also concerned to understand the impact of this position on the allowance that the AER has granted UED for IT capital expenditure.

After reviewing both documents UED believes that the position presented by the AER and Nuttall Consulting is incorrect and does not accurately portray information that UED provided during the process and has failed to understand the future IT strategy.

UED considers the current IT environment, both infrastructure and applications, to be agile and flexible in line with UED's responsibility to manage services in a prudent manner.

6.10.10 UED has an Agile Infrastructure Architecture

6.10.10.1 Virtualisation

UED understand from reviewing the report that Nuttall Consulting believes that the Victorian DNSPs, including UED, have not taken advantage of virtualisation technologies and therefore have a limited and inflexible IT infrastructure architecture.

UED believe that the AER and Nuttall Consulting have failed to recognise that UED have been using virtualisation technologies for over 5 years and are currently utilising technologies from companies such as VMWare, Sun, IBM, HDS, EMC and Citrix to provide different capabilities across the infrastructure landscape. This was highlighted in the Technical Reference Model that was provided to the AER as supporting information.

UED has provided the AER and the Nuttall Consulting with its proposed operating platform, including details on data centre migration strategies. The information provided clearly demonstrates an approach which remains focused on both further augmentation and expansion of agile IT infrastructure and computing, it is therefore very concerning that the AER and Nuttall consulting have formed a view that UED IT infrastructure is not agile.

UED has been driven to sourcing alternative data centre facilities due to the high demands required to support the roll out of AMI. Both of the existing UED data centres were independently assessed and determined to be unable to meet the power and space requirements, these sites were the HP/EDS Tally Ho Data Centre and the UED owned secondary site at Burwood

Therefore, in order to meet the industry mandated timeframes and service levels the decision was made to implement AMI infrastructure into two new sites at EDC Mitcham (AMI Production) and Primus (AMI Disaster Recovery).

UED has continued the trend of implementing virtualisation technologies during the architecting and delivery of the AMI project. Where possible, the applications have been deployed onto highly efficient technical platforms either through software (e.g. VMWare) or hardware (e.g. Sun Blade Centres). In addition, the project has deployed a new Storage Area Network (SAN) that supports storage virtualisation.

As discussed with the AER and Nuttall Consulting, UED are committed to relocating from the Tally Ho Data Centre to the EDC Mitcham Data Centre in 2010. This project is underway with phase 1 (planning and definition) scheduled for completion in mid August 2010.

As part of this DC rationalisation process, UED intend to add additional capacity to the existing platforms to support the non-AMI applications. UED presented this view to the AER and Nuttall Consulting and believe that using the AMI platforms as a base and building further capacity is a prudent approach and is in line with the direction suggested in Nuttall Consulting's report.

6.10.10.2 Cloud Computing

UED recognise that there is a significant move within the IT industry towards utility based computing where services can be bought on demand. This model of computing provides organisations with access to almost limitless IT computing power and capability.

There are opportunities for UED to utilise cloud computing capabilities to supplement internal IT capabilities (e.g. provision of development / test machines), however, UED does not believe that the market has sufficiently matured in Australia to warrant a large scale deployment of critical applications (e.g. databases, CIS) to service provider IT equipment. The timing of any shift towards adoption of cloud computing has been discussed on a regular basis with our major IT service providers which includes IBM, Logica, Accenture and Deloittes. There is a common or shared view that cloud computing has not yet reached maturity in Australia. It is acknowledged by UED that there may some potential for use of cloud computing for development and testing activities purposes for projects requiring delivery of large scale test environments at short notice.

UED will carefully monitor this space over the forthcoming regulatory period to ensure that opportunities to leverage this new architecture are taken if and when they align with UED's principles and the market in Australia has matured sufficiently to warrant a deployment of capabilities to service provider infrastructure. UED believes that any move towards "cloud computing" should be taken gradually and carefully as there are significant risks (e.g. security, vendor lock-in) that need to be managed.

6.10.11 UED has an Agile Application Architecture

6.10.11.1 Service Oriented Architecture

UED is in the process of transforming the way applications integrate through the deployment of a new WebMethods platform and Service Oriented based architecture as part of the AMI project. As outlined in the IT Strategy, UED intends to consolidate all application integration onto this platform which will allow UED to utilise a flexible set of design principles and develop a loosely-integrated suite of services that can be reused across the business.

Service Oriented Architecture (SOA) provides businesses with increased agility and flexibility benefits and increases the level of re-use across application development and integration initiatives. The approach adopted by UED is consistent with an agile and flexible approach to application architecture.

6.10.11.2 N-Tier Architectures

UED supports the separation of different layers of the IT application architecture so that the presentation, application processing and data management processes within the application are logically separated from one another. This simplifies future modification which therefore reduces the ongoing cost to manage.

In addition, to separating processes within the application there is also the capability to separate the processes out physically through the deployment of separate infrastructure tiers (e.g. browser, web server, application server, database server). This provides IT organisations with increased opportunities to consolidate on a single infrastructure platform which maximises the overall investment.

UED recognises the benefits of N-tier architectures and has deployed this type of architecture in the current environment to create a flexible and reusable application and infrastructure environment.

6.10.12 What is AER's view on flexible and agile architecture?

From an IT perspective, UED plays a key role as a member of AEMO and currently is responsible for chairing the Energy Market Information Technology Reference Group. The charter of this group is to identify and consult on the future direction of IT for the energy market. UED is not aware of any trends or obligation based drivers within the Australian electricity market to move towards a flexible / agile architecture based on "cloud computing" or "Infrastructure as a Service" services.

UED intends to raise this as a point for discussion at the EMITRG to determine what the shared understanding is of all market participants on whether this architecture has been used, or should be used, to provide infrastructure capability to critical systems (e.g. SCADA, CIS, ERP, GIS, Market Systems) and to understand whether AEMO has any future role in providing this type of service to participants.

UED are not aware of any other market participants who utilise "cloud computing" or "Infrastructure as a Service" services to provide critical systems.

6.10.13 Should UED be able to absorb future major unplanned IT change?

The AER have specifically called out the need for Victorian Electricity Distributors to have a "flexible architecture" that can respond to industry changes in the future in a rapid and cost efficient manner.

In fact, the Nuttall report goes so far as saying that:

> "Many of the strategy documents did not discuss or mention agility or the intention to provide their business with a flexible architecture that would be able to respond to the changing needs to the business"

UED understands that the AER has formed this view as a direct result of its belief that a major change, such as AMI, should have been planned for in previous submissions and therefore should have been absorbed into the existing environment with minimal impact.

Whilst UED agrees with the AER that IT architecture should be flexible and agile, UED believe that the view presented in the draft decision does not take into account the significant level of change that the AMI mandate brought to Victorian distributors.

From an application perspective, the new business and industry changes required the implementation of new technologies (e.g. smart meters, RF mesh network, meter data management systems, mobility services to support the mass rollout) which required new IT applications to be deployed. UED believes that it is unrealistic of the AER to expect UED to be able to anticipate and therefore cost the implementation of new applications for requirements that were undefined before the completion of the last EDPR process.

From an infrastructure perspective, whilst spare capacity could have been implemented in UED data centres or "capacity on demand" could have been procured as a service (e.g. cloud computing). This does not take into account a number of other important guiding principles that UED believes are important and prudent when making IT investment decisions. Whilst cloud computing services are becoming increasingly common for commodity IT services (e.g. email), they are not common for business critical systems such as SCADA, Oracle NMS, GE Smallworld. There is no experience of electricity distribution utilities using these services for delivering core business applications.

Based on these reasons, it is unrealistic for the AER to expect UED to build an IT environment in the future that is able to completely adapt and absorb major industry changes such as AMI.

6.10.14 Conclusion on IT capital expenditure

After careful consideration of the AER and Nuttall Consulting findings, UED recommends that the AER approves the original capex amount proposed by UED, adjusted for the revised forecast for the SAP program, plus the labour and material escalators to be determined for the final decision. For the purposes of this submission UED has applied the labour and material escalators determined as part of this response. A table of the revised forecast is provided below:

Table 6-6: Information Technology Capital Expenditure (real $M 2010)

	2011	2012	2013	2014	2015
Original	29.2	28.3	18.1	15.9	7.1

proposal					
AER draft decision	19.7	19.7	19.7	19.7	19.7
Revised proposal	23.5	36.5	27.6	16.0	7.2

6.11 Non-network assets - other

6.11.1 UED's Regulatory Proposal

UED's original Regulatory Proposal explained that this category of capital expenditure relates to the purchase of:

- vehicles;
- plant and machinery;
- miscellaneous tools & equipment; and
- office accommodation.

There are two main drivers for the proposed capital forecasts in this category:

- replacement of fleet; and
- property projects.

UED's original Regulatory Proposal explained that the fleet is being replaced and purchased consistent with UED's fleet asset management policy. Capital expenditure is also required to refurbish office space as UED in-sources functions that are currently contracted out.

6.11.2 AER's Draft Decision on "non network-other" capital expenditure

The AER have accepted UED's original proposal.

6.11.3 UED's response to the AER's Draft Decision on "non network-other" capital expenditure

UED has reviewed its original proposal to determine whether the company's forecast was inclusive of all "other" capital requirements. In particular the fleet component has been revised to more accurately reflect the fleet requirements for the forthcoming regulatory period.

The revised forecasts remain consistent with expenditure levels in the current regulatory period.

7. Depreciation

Key messages

UED's original Regulatory Proposal explained that:

- In accordance with clause 6.5.5(b)(3) of the Rules, actual depreciation has been calculated in accordance with the rates and methods allowed in the distribution determination for the current regulatory control period.
- UED has prepared its depreciation forecast for the forthcoming regulatory control period by applying forecast asset additions, forecast asset disposals, asset lives and the AER's roll forward model in accordance with Rules requirements.
- For the purposes of forecasting the cost of corporate income tax pursuant to clause 6.5.3 of the Rules, UED has calculated tax depreciation in accordance with the tax law and the applicable asset lives, and in accordance with the requirements of clause 11.17.2 of the Rules.

The AER's Draft Decision argued that:

- UED had proposed an accelerated depreciation of its sub transmission and distribution assets.
- The AER considers that a better way for UED to address this issue is to make adjustments to the remaining lives of assets. The AER considers that this is the appropriate method to address instances of assets having residual value for regulatory purposes at the time they are replaced

In this Revised Regulatory Proposal, UED explains that the accelerated depreciation approach proposed by UED was necessitated by specific capital replacement programs, and the relevant assets have now been identified in a separate asset class. This approach will ensure that assets that are planned to be replaced over the course of the next regulatory period will be appropriately accounted for in the regulatory asset base, in accordance with the approach advocated by the AER in the Draft Decision.

7.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal noted that in regulatory economics, depreciation is regarded as providing a return of capital to shareholders. As such, the timing of the return to shareholders is only relevant to the profile of network revenues and prices, but does not affect the total return in present value terms.

The original Regulatory Proposal also noted that the Rules establish broad principles for depreciation, although the Rules do not mandate a specific depreciation methodology. The AER's roll forward model handbook explains that the model is configured to use the straight-line depreciation method as the default position for calculating depreciation. Nevertheless, the handbook also comments that DNSPs may propose depreciation profiles other than the straight-line method in the roll forward model, subject to meeting the requirements in clause 6.5.5(b) of the NER[78].

UED used the AER's PTRM to calculate depreciation in accordance with Clause 6.5.5 of the Rules. New assets were depreciated according to standard lives for each asset class. Existing assets were are depreciated over their remaining asset lives. The asset lives applied buy UED are shown in the table below.

Table 7-1: Asset lives

	Economic life	Remaining life As at 1 January 2010
Sub – Transmission	60	24
Distribution system	35	24
Standard metering	n/a	5
Public Lighting	n/a	5
SCADA / Network Control	7	0
Non – network – IT	5	0
Non – network - Other	10	5

The remaining life for network related assets was obtained from the Network AMP. This document was provided as an appendix to UED's original Regulatory Proposal.

Pursuant to clause 6.5.5(b)(3) of the Rules, actual depreciation was calculated in accordance with the rates and methods allowed in the ESC's distribution determination that applies for the current regulatory control period, and is shown in Table 7-2 below.

Table 7-2: Regulatory depreciation 2006 - 2010 period

	2006 $M	2007 $M	2009 $M	2009 $M	2010 $M
Regulatory Depreciation	104.9	106.4	110.1	93.4	82.6

Amounts shown in real 2010 terms.

UED prepared its depreciation forecast for the 2011–2015 regulatory control period by applying forecast asset additions, forecast asset disposals and the asset lives shown in Table 7-1 above. The opening asset values were calculated in accordance with the AER's roll forward model. The regulatory depreciation allowance is shown in Table 7-3 below.

[78] AER, Electricity Distribution Network Service Providers, Roll forward model handbook, June 2008, page 3.

Table 7-3: Regulatory depreciation 2011 - 2015 period

	2011 $M	2012 $M	2012 $M	2014 $M	2015 $M
Regulatory depreciation	84.0	89.7	96.6	100.7	105.2

Amounts shown in real 2010 terms.

The original Regulatory Proposal noted that depreciation (return of capital) is consistent with the benchmarks in the current period despite the significant increase in capital expenditure forecast in the forthcoming regulatory period.

The original Regulatory Proposal also explained that for the purposes of forecasting the cost of corporate income tax pursuant to clause 6.5.3 of the Rules, UED calculated tax depreciation in accordance with the tax law and the applicable asset lives and in accordance with the requirements of clause 11.17.2 of the Rules Tax depreciation was calculated on a diminishing value basis, using applicable tax depreciation rates.

The forecast tax depreciation schedule for the 2011–2015 regulatory control period, which was used to calculate UED's allowance for corporate income tax, is shown in Table 7-4 below.

Table 7-4: Regulatory tax depreciation 2011 - 2015 period

	2011 $M	2012 $M	2012 $M	2014 $M	2015 $M
Regulatory tax depreciation	104.0	107.4	112.9	108.7	108.3

Amounts shown in real 2010 terms.

7.2 Further information provided by UED

After lodging its original Regulatory Proposal, UED was requested by the AER to provide further information regarding the depreciation of sub transmission and distribution system assets. In response to the AER's request, UED provided the following information on 19 March 2010:

Clause 6.5.5 of the Rules requires depreciation to be calculated using the value of assets included in the regulatory asset base (RAB) at the beginning of the regulatory year and the depreciation schedules either nominated by the DNSP or determined by the AER in circumstances where the DNSP's proposed schedules fail to comply with the following principles contained in clause 6.5.5(b):

1. the schedules must be based on a profile that reflects the nature of the assets (or category of assets) over the economic life of that asset (or category of assets);
2. the sum of the real value of the depreciation that is attributable to any asset (or category of assets) over the economic life of that asset (or category of assets) must be equivalent to the value at which that asset (or category of assets) was first included in the regulatory asset base (ie, the asset can only be depreciated once); and
3. the economic life of the relevant assets and the depreciation methodologies and rates underpinning the calculation of depreciation for a given regulatory control period must

be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

These requirements represent a significant departure from the depreciation methodology adopted by the Essential Service Commission (ESC) in the 2001 and 2005 Electricity Distribution Price Determination. The ESC explained its approach to depreciation in the following terms :

> "In applying the straight-line method for the calculation of regulatory depreciation, the Commission has not required the adoption of a standardised set of asset lives or classes. That is, it has adopted the asset lives proposed by the distributors. This 'hands-off' approach to determining regulatory depreciation reflects the fact that the rate of depreciation affects only the timing (rather than value) of cash flows. Additionally, consistent with the approach outlined in the 2001 Electricity Distribution Price Review, the Commission simply deducts the regulatory depreciation reflected in the price controls to determine the regulatory asset values in future regulatory periods — it does not recalculate the depreciation allowance for actual expenditure over the period."

In effect, the ESC's approach to depreciation allowed the distributor substantial discretion in managing the profile of depreciation. The rationale for this flexible approach is that different profiles of depreciation only affect the timing of the cash flow, but do not affect the net present value of the revenue stream.

Compared to Rule 6.5.5, the ESC's regime provided a much greater degree of flexibility in calculating annual depreciation. A transitional issue therefore arises in moving from the ESC's regime to the new regime required by Rule 6.5.5. For UED, the ESC accepted a comparatively long asset life (compared to the economic life) and low rate of depreciation for some asset categories. The effect of the longer asset life adopted in the 2005-2010 determination is that some assets will be replaced in the forthcoming regulatory period prior to the end of their notional lives. As 6.5.5(b)(1) requires the depreciation schedule must reflect the nature of the assets (or category of assets) over the economic life of that asset, a question arises regarding the appropriate method for recovering the remaining capital value of assets that will no longer be in service.

One approach to addressing this issue is to write off the remaining value of these assets over a more appropriate, shorter estimated remaining life. The difficulty with this approach, however, is that the net book value of assets that are no longer in service will be recovered over many years, which would be contrary to the requirements of Rule 6.5.5(b)(1). In particular, it would be difficult to argue that a depreciation profile that recovered capital costs for assets that no longer provided service properly reflected the nature of the assets over their economic life.

In light of this consideration, UED's preferred approach is to accelerate the depreciation for these categories of assets over the forthcoming regulatory period, to correct for the lower rate of depreciation over previous regulatory periods. UED's calculation applies an accelerated depreciation which is 31 per cent of the forecast replacement capital expenditure over the forthcoming regulatory period. This accelerated depreciation calculation only applies to the sub-transmission and distribution asset categories. UED considers this calculation to be a transitional measure as the company moves from the ESC's regime to the new requirements of Rule 6.5.5. In subsequent regulatory periods, it is expected that the depreciation charge will revert to a straight line approach.

A related transitional issue is the cash flow implications of moving from the ESC's flexible approach to depreciation to the less flexible requirements of the new Rules. Whilst UED recognizes that the requirements of Rule 6.5.5 must be satisfied, the ESC's observation remains valid that the choice of depreciation profile only affects the timing of the cashflow and does not affect the net present value.

In concluding its response to the AER's query, UED noted that the company would be concerned if the AER concluded that UED's depreciation profile did not satisfy the Rules, and in these circumstances UED requested further discussion of alternative options with the AER prior to the Draft Decision.

7.3 AER's Draft Decision on depreciation

Page 463 of the Draft Decision stated:

> "Essentially what United Energy is proposing is an accelerated depreciation of its subtransmission and distribution assets. The AER considers that a better way for United Energy to address this issue is to make adjustments to the remaining lives of assets. The AER considers that this is the appropriate method to address instances of assets having residual value for regulatory purposes at the time they are replaced…
>
> The AER considers that United Energy's additional depreciation has not been adequately justified as being in accordance with the requirements of clause 6.5.5(b)(1) and is not accepted by the AER. The making of ad hoc and large 'write offs' does not result in a depreciation profile that reflects the nature of United Energy's asset categories."

The AER's conclusion on remaining asset lives for UED is set out in **Table 7-5** of the Draft Decision (reproduced below).

Table 7-5: AER conclusion on remaining asset lives for United Energy (years)

Asset Category	2006-10 Standard asset lives for new capex	2011-15 Standard asset lives for new capex	2011-15 Remaining asset lives
Subtransmission	60.0	60.0	24.0
Distribution system assets	35.6	35.6	24.0
Standard metering	NA	NA	5.0
Public lighting	NA	NA	5.0
SCADA/network control	5.0	5.0	NA
Non-network general assets - IT	5.0	5.0	NA
Non-network general assets - other	7.5	7.5	5.0

Source – AER Table 10.15

7.4 UED's response to the AER's Draft Decision on depreciation

UED is pleased that the AER has accepted the company's proposal in relation to remaining asset life calculations and the depreciation rates for new capital expenditure. Since UED lodged its original Regulatory Proposal, the company has undertaken further work to specifically identify those asset classes that are subject to large replacement programs and which will no longer be in service at the end of the forthcoming regulatory period. The effects of these programs were not included in the remaining asset life calculations for in the original Regulatory Proposal or this Revised Regulatory Proposal.

7.4.1 Overhead service replacement program

Included in UED's capital program is a program to replace approximately 150,000 neutral screen services over the next five years. The full details of this program are included in UED's detailed asset management plan and asset strategy documents.

UED did not include the effects of this replacement program in the remaining life calculation. The existing assets will not be in service at the end of the forthcoming period (providing the AER accepts UED's proposed replacement program) and therefore these assets should be depreciated fully.

UED has identified that the regulatory book value of overhead services is approximately $114.4 million. UED intends replacing 23.8 per cent of services during the forthcoming regulatory period. Applying this percentage to the regulatory book value means that $27.3 million of the book value of services must be fully depreciated over the forthcoming regulatory period. UED has created a new asset class (neutral screen services) in the PTRM into which these particular assets have been allocated. As noted in the table below, these assets are to be depreciated over a period of 5 years.

7.4.2 Transformer program

Included in UED's capital program is a program to upgrade a number of overloaded transformers. This work is part of the reinforcement program rather than the replacement category. The calculation of remaining life value only includes expenditure categorised as replacement. Therefore the effect of the program to replace overloaded transformers has not been included in the average remaining asset life.

UED has approximately 13,000 transformers. UED expects to replace approximately 290 of these during the regulatory period due to overloading. These transformers are unlikely to be able to be used in other areas of the network and will be scrapped for spares.

This program represents approximately 3 per cent of the total population. The written down value of the assets to be scrapped is $5.6 million, and UED will fully depreciate that amount over the forthcoming regulatory period. UED has created an asset class (overloaded transformers) in the PTRM to reflect this amount and will fully depreciate this class of asset during the period in the same profile as they are replaced.

7.4.3 Asset life

The table below provides UED revised asset lives:

Table 7-6: Assets exceeding

	Economic life	Remaining life as at 1/1/2010
Sub – transmission	60	24
Distribution system	35.6	24
Neutral screen services	5	5
Overloaded transformers	5	5
Standard metering	n/a	5
Public lighting	n/a	5
SCADA/Network Control	7	0
Non-Network IT	5	0
Non- Network - Other	10	5

7.4.4 Forecast depreciation

Applying the assets lives shown above, the table below sets out the revised depreciation amounts for the forthcoming regulatory period.

Table 7-7: Regulatory Depreciation (real $2010 million)

	2011	2012	2013	2014	2015
Regulatory depreciation	75.2	85.2	96.9	107.3	114.0

8. Regulatory asset base

Key messages

UED's original Regulatory Proposal explained that:

- UED has applied a value of $1,220.3 million (real, 2004) as its opening asset base, in accordance with clause S6.2.1(c)(1) of the Rules.
- The roll forward of the regulatory asset base has been calculated in accordance with clauses S6.2.1(c) (1) and (2), S6.2.1(e) and S6.2.3 of the Rules, using the AER's Roll Forward Model.
- UED's opening RAB value at 1 January 2011 is $1,407.5 million (in 2010 dollars).

The AER's Draft Decision noted that:

- The AER has applied an opening RAB for UED of $1,387.7 million in 2010 dollars.
- The RAB applied by the AER is $19.8 million below the value proposed by UED.

In this Revised Regulatory Proposal, UED explains that the company accepts the AER's Draft Decision in relation to the RAB, noting that the AER's downward adjustment to UED's proposed RAB value is consistent with the Rules, it is inconsistent with past regulatory practice.

8.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal noted that clauses S6.2.1(c)(1) and (2) of the Rules specify how the opening RAB for UED as at 1 January 2006 is to be calculated. Table 8-1 below sets out the calculation in accordance with those provisions of the Rules.

Table 8-1: Opening regulatory asset base

	$M
Opening RAB as at 1 January 2006 (real 2004)	1,220.3
Convert opening RAB to 2010 prices	1,447.8
Less estimated 2005 values (2010 prices)	
Capital expenditure	-144.2
Customer contributions	1.3
Disposals	0.0
Plus actual 2005 values (2010 prices)	
Actual capital expenditure	99.5
Actual customer contributions	-14.5

	$M
Actual disposals	-1.3
Revised opening RAB as at 1 January 2006 (2010 prices)	**1,387.7**

The original Regulatory Proposal then proceeded to explain that UED is required to establish an opening value for the RAB as at 1 January 2011, which is the start date of the forthcoming regulatory period. In accordance with the Rules, UED applied the AER's Roll Forward Model, including adjustments for inflation, disposals of assets and estimates of capital expenditure for the 2009 and 2010 Regulatory Years.

Internal company forecasts of capital expenditure, customer contributions and asset disposal data for 2009 were applied in the Proposal. Depreciation was based on the amount allowed in the 2006 EDPR determination. The original Regulatory Proposal noted UED's intention to adjust the 1 January 2011 RAB value in its Revised Proposal to reflect actual 2009 data. It was further noted that adjustments to the regulatory asset base to reflect any remaining differences between the estimated and actual values will be made by the AER at the commencement of the subsequent regulatory period in accordance with the roll forward model.

Table 8-2 shows the roll forward of UED's regulatory asset base from 1 January 2006 to 31 December 2010.

Table 8-2: Roll forward of the RAB value from 1 January 2006 to 31 December 2010

	2006 $M	2007 $M	2008 $M	2009 $M	2010 $M
Opening RAB	1,387.7	1,381.5	1,359.0	1,334.3	1,365.2
Plus Capital expenditure	114.9	103.4	99.4	136.5	129.8
Less customer contributions	- 13.6	- 18.9	- 13.7	- 12.2	- 4.9
Less regulatory depreciation	- 104.9	- 106.4	- 110.1	- 93.4	- 82.6
Less disposals	- 3.6	- 0.5	- 0.3	- 0.0	- 0.0
Closing RAB	**1,381.5**	**1,359.0**	**1,334.3**	**1,365.2**	**1,407.5**

Amounts shown in real 2010 terms.

The original Regulatory Proposal explained that UED applied the methodology set out in Schedule 6.2.3 of the Rules, and used the AER's roll forward model to establish the RAB for each year of the forthcoming regulatory control period, as shown in Table 8-3 below.

Table 8-3: Regulatory asset base for 2011 - 2015

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Opening RAB	1,407.5	1,509.7	1,595.4	1,669.8	1,723.0
Plus Capital expenditure	209.4	198.8	195.9	180.0	158.5
Less customer contributions	- 23.2	- 23.4	- 24.9	- 26.1	- 26.1
Less regulatory depreciation	- 84.0	- 89.7	- 96.6	- 100.7	- 105.2

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Less disposals	- 0.0	- 0.0	- 0.0	- 0.0	- 0.0
Closing RAB	**1,509.7**	**1,595.4**	**1,669.8**	**1,723.0**	**1,750.2**

Note: The values contained in this table have been calculated as per the requirements of the PTRM. Amounts are shown in real 2010 terms.

8.2 AER's Draft Decision on the regulatory asset base

Page 453 of the Draft Decision State:

> "The AER has reviewed Victorian DNSPs' proposed opening RAB and the cost inputs to the RFM for the current regulatory control period and has cross checked these against their regulatory accounts. The AER has identified issues related to the Victorian DNSPs' RAB forward models as follows, and made adjustments to RAB accordingly, in relation to:
>
> - reconciliation of data inputs (as noted in section 9.5.1 of the Draft Decision)
> - adjustments arising from 2005 expenditure estimates (9.5.2)
> - escalation methodology for the RAB forward model (as noted in section 9.5.3)
> - financing cost for capex overspend (as noted in section 9.5.4)."

For the purposes of the Draft Decision, the AER has applied an opening RAB for UED of $1,387.7 million in 2010 dollars.

Page 454 of the Draft Decision proceeds to state:

> "The AER has also determined, under clause 6.3.2(a)(2) of the NER, that it will apply the same method to index the RAB as that used to escalate the form of control mechanism over the forthcoming regulatory control period. This will form part of the calculation of the opening RAB in the AER's distribution determination for the 2016–20 regulatory control period.
>
> In accordance with clause 6.12.1(18) of the NER, the AER will use actual depreciation for establishing the RAB for the commencement of the 2016–20 regulatory control period."

8.3 UED's response to the AER's Draft Decision on the regulatory asset base

The Draft Decision adjusts the RAB value proposed by UED to remove the time value of money that had been applied to the difference between actual and forecast capital expenditure in 2005. Whilst the removal of this allowance for the time value of money is inconsistent with past regulatory practice it appears to be consistent with the relevant provisions of the Rules and therefore UED's revised Roll Forward Model includes an adjustment to reflect the relevant provision of the Rules.

Therefore UED's opening 2011 asset base will be $1,387.7 million. The regulatory asset for the period is set out in the table below:

Table 8-4: Assets exceeding Regulatory asset base for 2011 - 2015

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Opening RAB	1,387.7	1,510.1	1616.2	1703.2	1743.8
Plus Capital expenditure	225.3	218.2	210.5	174.9	153.0
Less customer contributions	-27.7	-27.0	-26.5	-26.8	-26.0
Less regulatory depreciation	-75.2	-85.2	-96.9	-107.3	-114.0
Less disposals	0.0	0.0	0.0	0.0	0.0
Closing RAB	**1,510.1**	**1616.2**	**1703.2**	**1743.8**	**1756.8**

Note: The values contained in this table have been calculated as per the requirements of the PTRM. Amounts are shown in real 2010 terms.

9. Cost of capital and taxation

Key messages

UED's original Regulatory Proposal explained that:

- The provision of an adequate return on capital is of critical importance to UED's owners and its customers. An inadequate allowance for the cost of capital will make it extremely difficult for UED to compete for its required share of funding, which in turn will have adverse implications for the long term interests of consumers.
- In making a decision on UED's return on capital, the AER is required to consider the National Electricity Objective and the Revenue and Pricing Principles set out in the National Electricity Law. These provisions refer to the objective of promoting efficient investment in electricity services for the long term interests of electricity consumers. The provisions also set out important principles, including that:
    - A regulated network service provider should be provided with a reasonable opportunity to recover ***at least*** the efficient costs of providing network services; and
    - Prices for the provision of network services should allow for a return commensurate with the regulatory and commercial risks involved in providing the services.
- The Rules require the AER to err on the upside where uncertainty may exist or where measurement may be difficult, to ensure that required investment can proceed.
- UED's original Regulatory Proposal satisfied these requirements. It adopted the parameter values and methodologies set out in the Rules and the applicable statement of regulatory intent (SORI), with the exception of the values for the market risk premium (MRP) and the value of imputation credits (gamma). In the case of these two parameters, UED considered that there was persuasive evidence available which demonstrated that the values specified in the SORI for the MRP and gamma are inappropriate, and that for the forthcoming determination for UED, departure from those values would be justified, in accordance with the provisions set out in clauses 6.5.4(g) and (h) of the Rules.
- UED proposed a value of 8 per cent for the MRP, and a value of 0.5 for the gamma.
- The nominal vanilla WACC in the original Regulatory Proposal was 10.86 per cent.
- UED wrote to the AER to set out the measurement period of the nominal risk free rate (and debt risk premium) that the company proposed to be adopted for the purpose of the AER's final determination. In accordance with clause 6.5.2(c)(2)(iii) of the Rules, UED requested that the letter be kept confidential.

The AER's Draft Decision determined a nominal vanilla WACC of 9.68 per cent for the Victorian DNSPs, which is lower than the 10.86 per cent proposed by UED. The reduction is due to the combined effects of the following factors:

- In the Draft Decision, the AER dismissed the method proposed by the Victorian distributors to assess the suitability of the Bloomberg fair value yield curve for measurement of the debt risk premium. The AER did not provide satisfactory reasons for so doing. The AER also spurned the method put forward for extrapolating the BBB+ fair value yield curve out to a term of ten years.

- The AER has maintained the approach for measuring the DRP which it recently refined for the ActewAGL and ETSA final decisions. The DRP was determined from readings taken from the CBA Spectrum BBB+ fair value curve.
- The Draft Decision rejected the proposed MRP of 8 per cent, on the basis that the Victorian DNSPs' proposals did not constitute persuasive evidence to depart from the value of 6.5 per cent specified in the SORI.
- The Draft Decision updated the nominal risk-free rate for a 15-day period ending 19th March 2010. The risk free rate changed from 5.47 to 5.65 per cent.

Revised Regulatory Proposal:

- Caution in financial markets has been evident in the past couple of months, driven principally by concerns about European sovereign debt and banks, but also by some uncertainty about the pace of future global growth. Financial prices have been more volatile and equity prices and government bond yields in major countries have declined.
- An analysis of the implied volatility of the price on a 12-month call option suggests that the one-year, forward-looking MRP is 11.9 per cent. Officer and Bishop (2010g) have derived an average forward view of the MRP over the 2011 to 2015 period, and the calculated value is 8 per cent.
- The implied volatility measure has, for the most part, trended upwards over the first half of 2010. Conditions in financial markets remain unsettled, and the implied volatility is well above long run average values. A similar pattern is evident in UK and US financial markets.
- UED has accepted the MRP of 6.5 per cent which is specified in the SORI. However, in doing so, UED does not necessarily accept the correctness of this MRP or the AER's reasons for adopting it.
- The fundamental conclusion of the expert economists engaged by the Victorian distributors is that the AER methodology for estimating the debt risk premium is beset by errors.
- Following advice from PwC (2010g) and CEG (2010g), UED has devised a three-step method for estimating the DRP which corrects for the errors identified with the AER's method and its application.
- PwC (2010g) has recommended a debt risk premium of 428 basis points for an Australian BBB+ bond during the reference period, which covers the 30 business days from 19th April to 31st May, 2010 inclusive. UED has accepted the recommendation.
- The aforementioned value of the DRP has been obtained by reading off the Bloomberg BBB band fair value curve at 6 years, and then extending the estimate beyond that point using the change, from 6 to 10 years, in the debt risk premium that was observed under the Bloomberg AAA fair value curve.

In relation to the estimated cost of corporate tax:

- The Draft Decision rejected the Victorian DNSPs' proposed gamma value of 0.5 and instead adopted a value of 0.65.
- The AER has maintained its position that an appropriate distribution rate, or payout ratio for franking credits is 100 per cent. The purported justification is the Officer (1994) framework which assumes cash flows into perpetuity. The AER has relied upon the advice of Handley, who has suggested that the market average payout rate of 70 per cent should not be used because of the uncertainty attached to the value of retained imputation credits (represented by the parameter, psi).
- The AER has rejected the empirical estimate of theta (0.23) derived by SFG Consulting using dividend drop-off analysis. SFG made numerous refinements to its approach in response to the AER's comments subsequent to the ETSA Draft Decision; however the AER has refused to concede that SFG has arrived at a valid and defensible result. SFG also undertook extensive auditing and checking of its data.
- The AER estimate of theta is based on an average of the 'lower' and 'upper' bound estimates derived, respectively, from the Beggs and Skeels (2006) dividend drop-off study and the Handley and Maheswaran (2008c) analysis of tax data for foreign investors in Australia. The Beggs and Skeels (2006) estimate is 0.57, obtained via econometric analysis of stock price changes. The Handley and Maheswaran (2008c) estimate is calculated as an average of the upper values (0.67 and 0.81) obtained from an evaluation of tax statistics over two time periods. The AER 'upper bound' is therefore 0.74. The overall estimate of theta put forward by the AER is 0.65 (which is evaluated as the mean of 0.57 and 0.74).
- The AER combines its estimate of theta (0.65) with a presumed payout ratio of 100 per cent to derive an overall value for gamma of 0.65.
- The Draft Decision adopted the lower corporate tax rates proposed in the Rudd Government's response to the Henry Tax Review.

In this Revised Regulatory Proposal, UED explains that:

- The AER has ignored the weight of empirical evidence which demonstrates that the distribution rate is not 100 per cent, and is in fact likely to be around 70 per cent. The consultants engaged by AER have themselves acknowledged that the distribution rate is below 100 per cent.
- The AER continues to assert that a 100 per cent distribution rate is consistent with the Officer WACC framework, even though this has been denied by Professor Officer himself (see Officer, 2009f). Hathaway (2010g3) has also confirmed that the Officer (1994) framework does not require a 100 per cent payout ratio.
- The tax study by Handley and Maheswaran (2008c) has been discredited, as a result of investigations undertaken by Hathaway, and reported in Hathaway (2010g1). The data used in the Handley and Maheswaran (2008c) study was contrived and the results are therefore invalid. The AER should resile from using the flawed results of this published work. To-date, the AER has used Handley and Maheswaran (2008c) to derive an "upper bound" for theta, notwithstanding the deficiencies. The AER also appears to have misinterpreted the results of this study

in deriving its "upper bound".

- The SFG studies (2009b and 2010a) provide sound empirical estimates of theta. The AER has relied on just one dividend drop-off study to estimate theta, notwithstanding the advice of its experts to take a more "balanced approach". The AER has cavilled at the more recent SFG (2009b and 2010a) studies, despite expert evidence to suggest that the results from this work are at least as reliable as the results from the Beggs and Skeels (2006) research paper.
- UED maintains that an appropriate estimate of theta is 0.2379, as supported by the comprehensive dividend drop-off study undertaken by SFG. The payout ratio is 69 per cent, giving rise to an overall gamma value of 0.164. UED has adopted 0.20 for the purposes of this Revised Regulatory Proposal.

9.1 Recap on UED's Regulatory Proposal

9.1.1 Considerations relevant to regulatory decision making on WACC

UED's original Regulatory Proposal noted that the provision of an adequate return on capital is of critical importance to UED's owners and its customers. In particular, regulatory decision-making that results in the provision of an inadequate post-tax return will damage incentives for investment, and will ultimately deny customers the economic benefits that flow from distribution network investment.

The original Regulatory Proposal noted that in making a decision on the cost of capital the AER should consider its broader obligations under the National Electricity Objective (section 7 of the National Electricity Law) and the Revenue and Pricing Principles (section 7A of the National Electricity Law). Relevantly, these provisions refer to the objective of promoting efficient investment in electricity services for the long term interests of electricity consumers. These provisions also set out important principles, including that:

- A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient cost of providing network services. The Australian Competition Tribunal recently made some observations in relation to why the NEL principles require that a regulated NSP should be in a position to recover "at least" its efficient costs, noting that "the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs."[79]
- Prices for the provision of network services should allow for a return commensurate with the regulatory and commercial risks involved in providing the services.
- Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider.

[79] Energy Australia and Others [2009] ACompT 8, paragraphs 77-78.

The original Regulatory Proposal also noted that UED faces a large capital expenditure programme over the next regulatory period. As a result, UED (via its parent company) will be seeking to raise capital from investors to fund its capex requirements. Without a doubt, the uncertain economic environment within which this must be achieved will create large challenges for our capital raising.

Within this context, it is important for the AER to ensure that the regulatory WACC allowance provides a reasonable opportunity for UED to deliver a level of prospective returns which are both commensurate with the risks that UED faces, and meets the expectations of investors. Failure to take such commercial considerations into account could result in funds being shifted away from the regulated energy network sector, to other similar risk investments which offer better returns. Such an outcome would be detrimental to the long term interests of consumers and hence, in conflict with the National Electricity Objective.

9.1.2 Overview of UED's proposed WACC and gamma value

The WACC parameters proposed by UED in its original Regulatory Proposal were derived in accordance with the Rules requirements and the broader principles set out in the National Electricity Law. The table below provides an overview of UED's original proposal.

Table 9-1: Overview of UED's original proposal

Parameter	Summary of value / methodology under the Rules and the SORI	UED's original proposal
Nominal risk free rate	Annualised yield on 10 year Commonwealth Government bonds based on an agreed averaging period.	Annualised yield on 10 year Commonwealth Government bonds based on an agreed averaging period.
Equity beta	0.80	0.80
Market risk premium	6.5%	8.0%
Value of debt as a proportion of the value of debt and equity (gearing)	0.60	0.60
Debt risk premium	To be based on a credit rating level of BBB+. The methodology and data sources used to determine the debt risk premium are not subject to specification in the SORI.	To be based on a credit rating level of BBB+ and to be sourced from Bloomberg subject to meeting test on indicators.
Value of imputation credits	0.65	0.50

As shown in the table above, UED proposed to accept the SORI requirements in relation to:

- the methodology (including the agreement of the measurement period) for calculating the nominal risk free rate;

- the equity beta value of 0.80;
- the value of debt as a proportion of the value of equity and debt (D/V) of 0.60; and
- the credit rating level of BBB+.

However, UED's original Regulatory Proposal set out persuasive evidence to justify a departure from the SORI requirements in relation to the value for the market risk premium ("MRP") and the value of imputation credits (γ). The arguments presented in the original Regulatory Proposal in support of UED's position on these two parameters are discussed below.

9.1.3 UED's nominal WACC in the initial Regulatory Proposal

UED proposed a nominal vanilla WACC of 10.86 per cent for the purpose of its original Regulatory Proposal. This was based on the parameter values set out in Table 9-2 below. The table also provides a cross-reference to the sections of chapter 9 of the original Regulatory Proposal that set out the information to substantiate the parameter value proposed by UED.

Table 9-2: Calculation of UED's nominal WACC in its original Regulatory Proposal

Parameter	Proposed Value	Section Reference to original Regulatory Proposal
Nominal risk free rate	5.47%	Section 9.4
Equity beta	0.8	Section 9.5
Market risk premium	8.0%	Section 9.6
Gearing (D/V)	60%	Section 9.7
Debt margin (excluding debt raising costs)	4.71%	Sections 9.8 and 9.9
Utilisation of imputation credits (γ)	0.50	Section 9.10
Cost of equity (K_e)	11.87%	
(Pre-tax) Cost of debt (K_d)	10.18%	
Nominal vanilla WACC	10.86%	
Real vanilla WACC	8.22%	

9.2 Summary of the Draft Decision on the WACC

For the Draft Decision, the AER has determined a nominal vanilla WACC of 9.68 per cent for the Victorian DNSPs, which is lower than the 10.86 per cent proposed by UED. The reduction is due to the combined effects of the following factors:

- The Draft Decision rejected the Victorian DNSPs' proposed method of estimating the debt risk premium which was based on the Bloomberg BBB fair value yield curve. The AER applied CBASpectrum's BBB+ fair value curve to the determination of the yield on the benchmark BBB+ 10 year corporate bond. The AER claimed that

CBASpectrum's BBB+ fair value curve best met the need for the return on debt to reflect the current cost of borrowings for comparable debt.

- The Draft Decision rejected the proposed MRP of 8 per cent, on the grounds that the Victorian DNSPs' proposals did not constitute persuasive evidence to depart from the value of 6.5 per cent specified in the SORI.
- The Draft Decision updated the nominal risk-free rate (from 5.47 to 5.65 per cent) for a 15-day period ending on 19th March 2010.

The table below summarises the WACC parameter values adopted in the Draft Decision.

Table 9-3: AER conclusion on WACC parameter values

Parameter	Draft Decision value
Nominal risk free rate	5.65%
Equity beta	0.8
Market risk premium	6.5%
Gearing (D/V)	60%
Debt margin (excluding debt raising costs)	3.25%
Cost of equity (K_e)	10.85%
(Pre-tax) Cost of debt (K_d)	8.9%
Nominal vanilla WACC	9.68%

In relation to the value of gamma, page XLIII of the Draft Decision stated:

> The AER considers that the value of 0.65 is the most appropriate estimate of gamma based on the reliable evidence currently available and that the Victorian DNSPs have not demonstrated a material change in circumstances to justify a departure from this value.

For the purpose of calculating the estimated cost of corporate tax, the Draft Decision adopts a reduced company tax rate on the basis of recommendations contained in the Henry Tax Review. The Draft Decision states[80]:

> The AER also notes more recent changes to corporate taxation arrangements announced by the Commonwealth Government on 11 May 2010, arising out of the Henry Review. Specifically, the Commonwealth Government will reduce the corporate tax rate to 29 per cent for the 2013–14 financial year and to 28 per cent from the 2014–15 financial year. The AER has determined that these changes should be reflected in the expected statutory corporate income tax rate under 6.5.3 of the NER and [the changes] have been applied in the AER's modelling of the DNSPs' tax building block.

80 Page 555 of the AER Draft Decision

9.3 Risk-free rate

For its Revised Regulatory Proposal, UED proposes a nominal risk free-rate of 5.65 per cent by applying the method adopted by the AER in its draft decision.

The method was originally proposed by UED in its November 2009 Regulatory Proposal and subsequently accepted by the AER. It uses the 30 business day historical average of the annualised yield on 10 year Commonwealth Government Securities (CGS) from 19th April 2010 to 31st May 2010 (the UED averaging period). These yields are sourced from the indicative mid rates published by the RBA.

UED estimates the yield on 10 year CGS maturing over the 30 business days to 31st May 2020 by interpolating - on a straight-line basis - the yields on the CGS bonds maturing on 15th April 2020 and 15th May 2021. UED has applied this method in its post-tax revenue model.

The UED averaging period was proposed by UED in its November 2009 Regulatory Proposal and subsequently accepted by the AER. UED has also used this period to estimate the debt risk premium.

9.4 Equity beta

UED proposed an equity beta of 0.80 in its original proposal, and the AER accepted this value in its draft decision. UED has not revised its proposed equity beta.

UED considers that an equity beta of 0.80 reflects the lowest sustainable measure of systematic risk for an efficient electricity business.

9.5 Market Risk Premium

9.5.1 Discussion of the MRP in UED's initial Regulatory Proposal

The original Regulatory Proposal noted that in its assessment of the value of the market risk premium for the purposes of the SORI (AER, 2009e3), the AER took account of estimates of the implied MRP using dividend growth models, which pointed to a significant change in the forward- looking MRP. In particular, the AER observed that these estimates had changed from well below 6 per cent to well above 6 per cent. The direction of change was also consistent with the evidence from implied volatility measures of the Australian stock market and the prevailing level of credit spreads at the time relative to their historical levels.

The AER formed the view that on balance, the evidence which it had reviewed provided a sufficiently compelling case for a conclusion that the prevailing MRP was above the long term level of 6 per cent. In its decision on the SORI, the AER sought to reflect the evidence in support of a higher forward-looking MRP by lifting its previously adopted value by 0.5 per cent, however, the magnitude of the increase to the MRP was clearly constrained by the AER's desire to maintain "regulatory certainty and stability". To this extent, the increase in the MRP was lower than it would have been, had it been chosen to genuinely reflect prevailing conditions in the market for funds.

UED accepts that measuring the unobservable MRP is a difficult matter. However, UED's original Regulatory Proposal noted that under prevailing market conditions, there is a genuine risk that a cost of capital based on the SORI value of 6.5 per cent for the MRP will understate the true cost of capital and hence, not provide a reasonable opportunity for UED to recover 'at least' its efficient costs of operation. The original Regulatory Proposal provided detailed information to substantiate UED's view that current market indicators suggest that investors are now demanding significantly higher returns to provide new equity.

In particular, UED's original Regulatory Proposal argued that there is a strong case for the AER to depart from the value of the MRP specified in the SORI, given:

- the on-going uncertainty regarding the outlook for global economic and capital market conditions in the context of the global financial crisis;
- the new evidence presented in the original Regulatory Proposal regarding investors' forward-looking required rates of return in the present environment of on-going high uncertainty; and
- UED's contention – substantiated in section 9.6 of the original Regulatory Proposal - that under these circumstances, applying the MRP value specified in the SORI would deliver an outcome that is inconsistent with the National Electricity Objective and the Revenue and Pricing Principles set out in the National Electricity Law.

The original Regulatory Proposal noted UED's view that the matters referred to above are relevant factors (pursuant to clause 6.5.4(h)(2) of the Rules) that justify, in this particular case a departure from the MRP value specified in the SORI.

9.6 UED's response to the AER's Draft Decision on the MRP

9.6.1 Discussion of conditions in domestic and international financial markets

In its initial regulatory proposal, UED commented on conditions in global capital markets, noting that the global financial crisis had given rise to:

- A material increase in the cost of capital across both debt and equity markets.
- A general decline in the level of investor risk appetite.
- A reduction in liquidity and access to capital across virtually all markets; and
- A change in market views on acceptable gearing levels.

In its draft decision, the AER declined to acknowledge that there was ongoing instability in financial markets, and, instead, reported more optimistic comments about signs of stabilisation in both debt and equity markets. For instance, the AER quoted from the January 2010 edition of the IMF World Economic Outlook (see page 492 of the Victorian draft decision). The AER also fell short of disendorsing comments from third parties, such as TRUenergy, which suggested that market conditions were now placid (page 493 of the Victorian draft decision).

In hindsight, the perspective adopted by the AER seems to have been overly optimistic. International financial institutions and development agencies are currently less sanguine about the prospects for global economic recovery, and have warned of possible threats to growth.

The International Monetary Fund (IMF) released an update of its World Economic Outlook on 8th July 2010, and warned that downside risks have risen sharply amid renewed financial turbulence (IMF, 2010g). The Fund stated that macro-economic developments during much of the spring had confirmed expectations of a modest but steady recovery in most advanced economies, and of strong growth in many emerging and developing economies. Global indicators of real economic activity were also strong through April, and stabilised at a high level in May. However, the Fund's prognosis for the world economy was also leaden with caveats:

> Nevertheless, recent turbulence in financial markets – reflecting a drop in confidence about fiscal sustainability, policy responses, and future growth prospects – has cast a cloud over the outlook. Crucially, fiscal sustainability issues in advanced economies came to the fore during May, fuelled by initial concerns over fiscal positions and competitiveness in Greece and other vulnerable euro area economies.
>
> Concern over sovereign risk spilled over to banking sectors in Europe. Funding pressure re-emerged and spread through interbank markets, fed also by uncertainty about policy responses. At the same time, questions about sustainability of the strength of the global recovery surfaced. As risk appetite waned and markets scaled back expectations for future growth, assets in other regions, including emerging markets, also experienced substantial sell-offs. This spilled over into sharp movements in currency, equity, and commodity markets. In principle, the renewed financial turbulence could spill over to the real economy through several channels, involving changes in domestic and external demand and in relative exchange rates. The supply of bank credit could be curtailed by heightened uncertainty about financial sector exposure to sovereign risk as well as increased funding costs, notably in Europe. Moreover, lower consumer and business confidence could suppress private consumption and investment. Fiscal consolidation could also dampen domestic demand. To the extent that higher risk premiums were accompanied by depreciation of the euro, the latter would boost net exports and mitigate the overall negative effect on growth in Europe. However, the negative growth spillovers to other countries and regions could be substantial because of financial and trade linkages.

In a further section of the World Economic Outlook update (IMF, 2010g), the IMF has articulated more fully its views about the downside risks to global economic growth:

> In the near term, the main risk is an escalation of financial stress and contagion, prompted by rising concern over sovereign risk. This could lead to additional increases in funding costs and weaker bank balance sheets and hence to tighter lending conditions, declining business and consumer confidence, and abrupt changes in relative exchange rates. Given trade and financial linkages, the ultimate effect could be substantially lower global demand.

The Fund's global projection model (GPM) has been used to illustrate the likely effects on growth of amplified levels of financial stress and contagion.

The Fund is by no means the only multi-lateral institution to express caution about conditions in debt and equity markets. The World Bank (International Bank for Reconstruction and Development) has also reserved its judgement about the prospects for the world economy, and has drawn attention to the possibility of a further tightening in credit markets, and of bank solvency issues resulting from sovereign debt difficulties in Europe. The Bank has also raised the spectre of a default or restructuring of high-income country sovereign debt. The key messages from the Bank's Global Economic Prospects report, released in June 2010 (IBRD, 2010f), can be summarised as follows:

- Market nervousness concerning the fiscal positions of several European high-income countries poses a new challenge for the world economy. This arises as the recovery is transitioning toward a more mature phase during which the influence of rebound factors (such as fiscal stimulus) fades, and GDP gains will increasingly depend on private investment and consumption.
- So far evolving financial developments in Europe have had limited effects on financial conditions in developing countries. Although global equity markets dropped between 8 and 17

per cent, there has been little fallout on most developing-country risk premia. And despite a sharp deceleration in bond flows in May, year-to-date capital flows to developing countries during the first 5 months of 2010 are up 90 percent from the same period in 2009.

- Little real-side data is available to evaluate the impact of the European fiscal/debt crisis on economic activity. Existing data suggests that through the end of March, the recovery remained robust in most developing and developed countries, with the exception of high-income Europe where it has stagnated.

- Assuming that measures in place prevent today's market nervousness from slowing the normalization of bank-lending, and that a default or restructuring of European sovereign debt is avoided, global GDP is projected to increase by 3.3 percent in 2010 and 2011, and by 3.5 percent in 2012.

- However, should current uncertainty regarding developments in Europe persist, outturns could be weaker. A high probability alternative baseline, characterized by an accelerated tightening of fiscal policy across high-income countries, would see a more muted recovery, with global GDP expanding by 3.1 per cent in 2010 and by 2.9 and 3.2 in 2011 and 2012. The easing of momentum would be concentrated in high-income countries, where GDP might rise 2.1, 1.9, and 2.2 percent during each of the three years.

- Deeper and more widespread effects might arise if the situation causes investors to become significantly more risk averse; or in a less likely scenario, if there is a major crisis of confidence, prompted by (or causing) a default or major restructuring of high-income sovereign European debt.

  - Simulations suggest that an increase in risk aversion that caused long-term yields on U.S. government bonds to rise by 100 basis points could slow global growth by 0.5 percentage points.

  - A serious loss of confidence in the debt of five EU countries combining high fiscal deficits and high government debts that led to a freezing-up of credit in those countries could cause GDP growth to slow by as much as 2.4 percent in 2011 — pushing high-income countries into recession.

  - A default or major restructuring among the EU-5 (Greece, Ireland, Italy, Portugal and Spain) could threaten the solvency of several banks outside the EU-5, with potentially far-reaching consequences for the global financial system.

The Organisation for Economic Co-operation and Development (OECD) has also been somewhat guarded about the prospects for world economic growth, and has emphasised the uncertainties and challenges in financial markets. In this respect, the OECD has echoed the sentiments expressed by economists at the IMF and the World Bank. In the OECD Economic Outlook, released in May 2010 (OECD, 2010e), the Organisation mentioned the revival in economic activity, which was in evidence across developed economies, but was also firm in its indications that an otherwise moderately encouraging outlook could be jeopardised by significant risks:

> A first substantive risk is related to developments in sovereign debt markets. While originating in some euro-area economies, instability has spread to other euro-area members and sovereign debt markets in other parts of the world.

Furthermore:

> These risks indicate that policy challenges are substantial and more demanding than appeared to be the case a few months ago.
>
> Prompt and massive response by euro-area governments and the European Central Bank have calmed financial market turbulence. But the region's underlying weaknesses are far from settled. Fiscal consolidation has been stepped up and front-loaded in some countries. But fundamental structural adjustment programmes will have to be implemented, as announcements alone may not be enough to secure credibility in consolidation strategies.

> In the autumn of 2008 the peak of the financial crisis led to unprecedented and coordinated policy responses that prevented the recession from becoming more severe and long lasting. Recent action taken by euro-area countries, also in coordination with other major economies, is of comparable dimension and momentum. Both have been welcome and necessary, and have been taken under the pressure of rapidly evolving circumstances. The fact that the second set of actions has been taken eighteen months after the first is a reminder that the period of significant financial instability that began in August 2007 is not yet over.

The considered judgement of economists at the IMF, OECD and the World Bank does not appear to resonate with the AER, which has instead adopted a more bullish stance, referring to the resurgence in the Australian share market in 2009, and an increase in equity issuance to fund investment (page 492 of the Victorian draft decision). The AER has asserted that the growth in equity raisings is symptomatic of improved confidence in the business sector.

It should be noted that, as at 15th July 2010, the ASX 200 had fallen by 8.38 per cent per cent over the calendar year-to-date. The downturn in equity markets over the first half of calendar 2010 has been acknowledged by the Reserve Bank of Australia in its recent monthly statements of monetary policy. For instance, in the June statement by Glenn Stevens, Governor of the Monetary Policy Division, the RBA expounded on the effects of the sovereign debt difficulties in Europe (RBA, 2010f):

> Since the Board last met, concerns about sovereign creditworthiness in several European countries have been a focus of financial markets. Investors have generally displayed a good deal more caution. As a result, equity prices have fallen and long-term government bond rates have declined outside of the countries most affected by the sovereign concerns. The Australian dollar fell sharply as part of this adjustment. Commodity prices have also softened, though those important for Australia remain at very high levels.

And, similarly, in the statement of monetary policy released in July 2010 (RBA, 2010g):

> Caution in financial markets has been evident in the past couple of months, driven principally by concerns about European sovereigns and banks but also by some uncertainty about the pace of future global growth. Financial prices have been more volatile and equity prices and government bond yields in major countries have declined. Some tightness in funding markets is evident, though not on the scale seen in late 2008.

In view of the adverse conditions in financial markets, UED considers that the AER's dismissal of evidence advanced by the Victorian distributors in relation to the market risk premium, is premature. The AER has asserted that "statements from central monetary agencies indicate that an MRP of 6.5 per cent may even be generous if market conditions continue to improve."

The AER has quite clearly failed to properly evaluate the recent economic assessments undertaken by international financial institutions and development agencies, including the IMF, the OECD and the World Bank. The AER has also disregarded recent commentaries on monetary policy issued by the RBA.

In its Regulatory Proposal, UED expounded on the effects of the global financial crisis on the forward-looking MRP and the cost of equity. UED considered that there was strong justification for an MRP above 6.5 per cent. In view of current developments in domestic and international financial markets, UED has concluded that its previous arguments remain valid.

9.6.2 Officer and Bishop implied volatility analysis

9.6.2.1 Assessment of a forward-looking MRP

Officer and Bishop (2010g) have completed a full update of their analysis of the market risk premium using the volatility of prices on call options. Their preliminary report on this subject was submitted to the AER in November 2009, as part of UED's regulatory proposal. In their latest report, Officer and Bishop (2010g) have also addressed criticisms levelled at their work by the AER, and have managed to refute all of the comments which were aimed at undermining the data and methods upon which they have relied.

Officer and Bishop (2010g) have noted that underlying volatility in the stock market remains well above the historical average, despite having diminished since the peak of the global financial crisis before rebounding. The current forward view of market volatility is at a similar level to that recorded when the South Australian draft decision was handed down in late November 2009. The implied volatility on a 12-month maturing option peaked at 43 per cent in January 2009, but then fell to 24 per cent by 16th December 2009, which was the closest trading date to the end of the 2009 calendar year. Over the 15-day period to 5th July 2010, the average implied volatility on a 12-month call option was calculated to be 23.7 per cent, which is 76 per cent above the long term average recorded volatility of 13.5 per cent. A 12-month call option was the longest duration financial instrument of this type available to be analysed.

The 13.5 per cent average implied volatility of a 12-month call option on the ASX 200 index was reported immediately prior to the sharp decline in equity markets which heralded the onset of the global financial crisis. For comparison, the average of the annualised 90 day standard deviation on the ASX 30 daily index was 14 per cent over the period from 1980 to the end of December 2009. At present, the implied volatility of 23.7 per cent is approximately 76 per cent above the long-term average reading of 13.5 per cent.

In order to derive a forward-looking MRP from the implied volatility data, Officer and Bishop (2010g) assumed a constant required rate of return per unit of risk. Their estimate of the unit price of risk is implicit in empirical assessments of the parameters of the CAPM, and was worked out as being 50 basis points. This was obtained by dividing a 7 per cent long term average MRP with the annual average standard deviation of 14 per cent. The 7 per cent long run average MRP is the best available assessment by Officer and Bishop, and is discussed in their report (page 22) with reference to other research papers which they have authored, such as Officer and Bishop (2009a).

Officer and Bishop (2010g) applied the required market risk premium per unit of risk to the current implied volatility, thereby deriving an implied MRP of 11.9 per cent (= 23.7 per cent * 50 b.p.). As has been mentioned, the implied volatility of 23.7 per cent was obtained as an average over a 15-day period to 5th July 2010. The choice of fifteen days was guided by comments made by the AER in the Victorian draft decision (page 500). However, any reasonable length of time can be selected for the analysis, and UED may indeed engage Officer and Bishop to evaluate the implied volatility of 12-month call options over the averaging period which has been nominated for measurement of the risk free rate in the lead up to the AER's final decision.

Officer and Bishop interpreted their 11.9 per cent as an upper bound which would be applicable over the short to medium term. The minimum period of validity of the estimate would be one year because the implied volatility was derived from a one-year maturing option. The authors stated categorically that an MRP based on the mean or long term average would not reflect the opportunity cost of capital over the forthcoming five-year regulatory period, and would therefore be insufficient to encourage investment under current conditions (page 5 of their report). Officer and Bishop also commented on recent patterns and trends in implied volatility, and observed that the behaviour of risk in the recent past had been relatively unusual. This is because prior periods of wide fluctuations in equity markets hadn't been characterised by prolonged intervals of above or below average risk. The authors therefore considered that their views about a higher MRP were vindicated by the current unusual set of circumstances.

9.6.2.2 Glide path profile for the MRP

Officer and Bishop considered the insights that might be offered by an examination of changes in implied volatility. The knowledge gained is primarily about the period over which the MRP is likely to remain above the average. They developed a trading strategy which used information in the implied volatility series to invest in the All Ordinaries index. Their approach was influenced by the clear (and expected) negative relationship between risk and observed return that is demonstrated in Figure 7 of their report (Officer and Bishop, 2010g). The strategy was essentially that:

- If implied volatility is above the historical average, then invest long. It was assumed that practitioners would make the assessment on a rolling basis. The rationale for the approach was that above average periods of risk would provide an opportunity to buy. When risk has reverted to the mean, then market capitalisation would be expected to recover, thereby providing a positive return to the strategy.
- Conversely, if the implied volatility is below the historical average, then market participants should invest short (or should short-sell).

The authors examined the return from the trading method over various holding periods and assumed that the particular assets would be liquidated at the end. They found that taking a long position when the proxy for implied volatility is above an historical average, and then holding for five years, provided a gross return of 16.6 per cent. This compared with a return of 13.1 per cent from a simple buy and hold strategy undertaken without regard for movements in the implied volatility series. The difference between the two approaches is +3.5 per cent. The uninformed buy and hold approach consists of purchasing when the (very) first trade has been executed under the more active strategy, and then holding the particular asset until the absolute last trade.

At the same time, selling short when the implied volatility series is below the historical average delivered a return of -10.5 per cent. The loss from this trading strategy would be less negative than the loss (-13.1 per cent) from a simple, uninformed short-selling approach.

When taken together, the 'buy and hold' and 'short-selling' trading strategies guided by implied volatility would provide an improved return, over five years, of 6.1 per cent [=(16.6 per cent-13.1 per cent)+(-10.1 per cent-(-13.1 per cent))]. The enhanced return is assessed by comparison with more passive, uninformed approaches. Consequently, Officer and Bishop concluded that implied volatility is a better predictor of the future return on the market (and by implication, therefore, the market risk premium) than an historical average return.

The more active trading strategies beat the simple buy and hold, and the simple short selling approach, in all cases. Officer and Bishop stated that this outcome is consistent with a competitive and efficient market, which uses all available information, because the trading strategies will have more risk.

The authors were also able to draw inferences about the predictive ability of the implied volatility measure. They were interested in assessing the length of time before the market would recover from a fall, and assumed that the period which delivered the best results from a trading strategy would signal the appropriate interval for a full recovery. The results in Table 1 of their report (page 17) suggest that the highest return is associated with holding for four years, with holding periods of longer than three years providing returns which surpass those available from shorter periods. The results would also support a trading horizon of five years, which, of course, is the time interval that coincides with a regulatory control period.

Evidence from BT Australia, cited in the Officer and Bishop (2010g) report, demonstrates that the duration of time over which the stock market recovers from a severe crash is generally between 5.5 and 6.5 years (page 13 of the report). This scenario is relevant to the current circumstances which can be described as a severe crash.

Officer and Bishop developed glide path profiles for reversion of the MRP from the 13.2 per cent upper bound to the long term average value of 7.0 per cent. Different scenarios for reversion were considered, with each one varying according to the time period for decline to the long term average. A geometric average of the MRP was calculated over the regulatory period. The MRP for 2011 is 11.9 per cent because this is the one-year view assessed using data from call options in June and July 2010.

In the first scenario, the MRP declines to 7.0 per cent by 2012, and then remains at that level until 2015. The geometric average of the MRP over the five year period to 2015 is then calculated to be 8.0 per cent.

9.6.2.3 Response to AER criticisms of the Officer and Bishop implied volatility analysis

The AER has sought to undermine the implied volatility analysis through a number of arguments which Officer and Bishop have refuted in their current paper. The concerns expressed by the AER had been in respect of the October 2009 report, Officer and Bishop (2009j).

Firstly, the AER has reported that the implied volatility on the ASX 200 index is returning back to historic levels (page 500 of the Victorian Draft Decision). Officer and Bishop (2010g) draw upon recent data to show that this is clearly incorrect. Figure 1 of their report demonstrates that observations of implied volatility have, in the main, been trending upwards in the second quarter of 2010. Accordingly, the comment by the AER that equity market volatility is waning seems to be entirely misplaced.

Secondly, the AER has questioned the use of implied volatilities on call options, suggesting that consideration be given to the implied volatilities on put options, or on an average of calls and puts. Officer and Bishop (2010g) respond that a longer time series of data is available for calls than for puts, thus providing a greater opportunity to examine oscillations in the series, and to relate the implied volatility to historical measures.

The need to use data over an extended period is made apparent by Figure 6 of Officer and Bishop (2010g). Figure 6 presents the relationship between the implied volatility, derived from the option price on a three month option on the ASX 200 index, and the annualised 30-day moving average of the standard deviation of the ASX 200 index itself. The graph therefore seeks to relate a forward looking measure of implied volatility to an historical, 30-day moving average series. The correlation coefficient between the two series was worked out to be 0.89.

A third issue raised by the AER is that the approach to estimating the implied volatility should be consistent with the method used to calculate other forward-looking WACC parameters, such as the risk-free rate. The AER suggested the use of a 15-day averaging period which would be consistent with the time interval over which the risk free rate was assessed for the purpose of the regulatory proposals submitted by the Victorian distributors in November 2009.

Officer and Bishop (2010g) have responded by measuring the implied volatility of the observations on a 12-month call option over a 15-day period ending on 5th July 2010. An average was then taken of the implied volatility results. As mentioned previously, there is scope for Officer and Bishop to update their analysis so as to cover the 20 business days of the averaging period which UED has chosen to be applied for the final decision.

9.6.2.4 Summary of the revised analysis by Officer and Bishop

The AER has presented its case that a diminution in equity market volatility means that a departure from a 6.5 per cent estimate for the MRP is unwarranted. In contrast, Officer and Bishop (2010g) have demonstrated convincingly that the current forward view of market volatility is much the same as it was in late November 2009, even though there has been a slight decline followed by an increase in the interim period.

Current volatility remains well above the historical average, and Officer and Bishop (2010g) therefore expect the risk premium on all financial instruments to reflect the current high levels of risk. Their one-year forward view of the MRP is 11.9 per cent and their average forward view over the 2011 to 2015 regulatory period is 8 per cent (page 3 of the report).

The current recommendations by Officer and Bishop are consistent with the estimates which they put forward in October 2009. In Officer and Bishop (2009j), the researchers worked out a one-year, forward-looking MRP of 12.2 per cent based on an implied volatility of 24.3 per cent. Their glide path analysis suggested an average MRP over the entire regulatory period in the range of 8 per cent to 10.6 per cent (see Table 2, Officer and Bishop, 2009j), however the researchers recommended 8 per cent which was at the lower end.

Officer and Bishop (2010g) have expressed concern that an MRP of 6.5 per cent would not reflect current economic conditions, and, similarly, would not be representative of the conditions that may prevail over the regulatory period. Current high levels of market risk demand a risk premium above the long term average and the implication, in their view, is that 6.5 per cent will not reward investors for the average market risk anticipated over the next five-year regulatory period.

The implied volatility analysis has considerable merit as evidenced by the appraisal of active trading strategies which are influenced by implied volatility. The market return from using information in the implied volatility to trade is higher than that which can be obtained from a simple buy and hold strategy. Officer and Bishop (2010g) have therefore concluded that the implied volatility is a better predictor of the future return on the market than the historical average return.

Officer and Bishop (2010g) have also reported fully on the manner in which they have incorporated the Brailsford et al. (2008) revised data into their long term estimates of the MRP.

9.6.3 Assessed value of the MRP by UED

The SORI (AER, 2009e3) specifies an MRP of 6.5 per cent. UED has conceded to an MRP of 6.5 per cent.

It should be noted, however, that UED does not necessarily accept the correctness of a 6.5 per cent MRP or the AER's reasons for adopting it. UED maintains its view that forward-looking estimates suggest an MRP higher than 6.5 per cent, particularly given the continued uncertainty surrounding economic and financial conditions.

The AER maintains that the value of 6.5 per cent for the MRP in the SORI (AER, 2009e3) reflected market conditions during the global financial crisis (page 492 of the Draft Decision). However, as per its original proposal, UED considers that 8 per cent is a better estimate of the MRP given current market conditions.

9.7 Gearing ratio

UED has incorporated the AER's gearing ratio of 0.60. UED considers that a gearing ratio of 0.60 is efficient for a stand-alone electricity distribution business and is consistent with UED's proposed cost of equity and debt risk premium estimates above.

9.8 Assessment of the debt risk premium for UED

9.8.1 Regulatory requirements

Clause 6.5.2(b) of the National Electricity Rules states that the return on debt (kd) is calculated as:

kd = rf + DRP

Where:

rf = the nominal risk-free rate

DRP = the debt risk premium for the regulatory control period determined in accordance with clause 6.5.2(e).

Clause 6.5.2(e) of the NER states that the DRP is:

> … the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency.

The SORI (AER, 2009e3) defined a maturity period of 10 years in relation to clause 6.5.2(d) for the nominal risk-free rate and a credit rating of BBB+ for the credit rating level (page 7). The underlying criteria used by the AER in its SORI in relation to the credit rating level were:

- The need for the rate of return to be forward looking that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services.

- The need for the return on debt to reflect the current cost of borrowings for comparable debt.

- The need for the credit rating level to be based on an efficient DNSP.

- The need to achieve an outcome that is consistent with the NEO.

- The need for persuasive evidence before adopting a credit rating level that differs from the level that has previously been adopted for it.

- The relevant revenue and pricing principles, which are:

  - Providing a service provider with a reasonable opportunity to recover at least the efficient costs.

  - Providing a service provider with effective incentives in order to promote efficient investment.

  - Having regard to the economic costs and risks of the potential for under and over investment (as per the NEL, Part 1, section 7a).

9.8.2 UED position on the DRP in its Regulatory Proposal

The Victorian electricity distributors commissioned PricewaterhouseCoopers (PwC) to provide advice on the reliability of Bloomberg-based debt risk premiums. PwC was engaged to investigate concerns that the process adopted by Bloomberg to calculating its fair yield curves was subjective and highly non-transparent.

PwC was requested to:

- Propose a methodology to test whether the Bloomberg fair value curves, upon which the AER had relied in previous determinations, conformed reasonably to the legislative requirements.

- Propose an alternative methodology for calculating the debt risk premium that best satisfied the legislative requirements in the event that Bloomberg failed the above test; and

- Apply the Bloomberg test and, if necessary, the alternative methodology over the first 15 trading days in October 2009.

The report written by PwC (PwC, 2009k) was submitted as an attachment to UED's regulatory proposal.

The principal findings by PwC can be summarised are as follows:

1. The decision to use data from Bloomberg to estimate debt risk premiums should be made by reference to three tests or indicators:

   - The level of dispersion across the opinions of the financial institutions that submit opinions on corporate bond yields to Bloomberg.

- The difference between the Bloomberg-determined yields for bonds and the central tendency of the opinions provided by financial institutions; and
- The average difference between the Bloomberg fair value yields for each of the bonds on issue, and the yields that Bloomberg determines for these bonds.

The structural tests were chosen because there was evidence that during the global financial crisis, the application of the Bloomberg fair value curve approach had resulted in a systematic under-estimation of the true cost of the relevant debt.

2. Bloomberg satisfied the requirements of the tests when data was used for the first 15 trading days of October 2009. In late 2009, Bloomberg only produced fair value curves out to a seven year term to maturity for BBB (as well as A and AA) corporate bonds. This meant that some form of extrapolation was necessary to derive an implied credit margin for a 10 year BBB bond. PwC (2009k) recommended that a linear extrapolation of the Bloomberg BBB credit margins between five and seven years be used for the calculation. The application of this estimation procedure resulted in a debt risk premium of 471 basis points.
3. PwC recommended that further analysis be undertaken in the event that Bloomberg failed a future application of the tests. The extent of the additional analysis would be determined by reference to the reasons for the failed test(s). PwC therefore put forward a range of analyses that could be undertaken in these circumstances.

UED proposed that the tests and analyses which had been recommended by PwC should be applied during the averaging period that had been nominated for the Draft Decision.

9.8.3 AER draft decision on the debt risk premium

In its Draft Decision, the AER examined the accuracy of the data sources that are used to determine the debt risk premium on a 10 year BBB+ Australian corporate bond. The sources are:

- The CBASpectrum BBB+ fair value curve; and
- The Bloomberg BBB band fair value curve. Since this curve extends out only to 7 years, the AER has extrapolated the debt risk premium from 7 years to 10 years using the change in the debt risk premium that was implied by the Bloomberg AAA band debt risk premium.

The AER also considered an average of the two curves, in keeping with its usual practice.

The relative accuracy of the two curves was tested by comparing the yields which they predicted with the yields on Australian BBB+ corporate bonds. The sample was restricted to bonds with a remaining term of more than 2 years. The important features of the AER's testing process were that:

- When establishing its pool of available bonds, the AER assessed that the Dalrymple Bay Coal Terminal (DBCT) bond was an outlier, and therefore excluded it.
- The AER did not test the reasonableness of its assumption about the extent to which the debt risk premium would increase beyond the boundary of the point at which the AER was able to assess the curves. The longest duration bond in the AER's sample

was only 5 years, and the AER's method did not objectively assess how the debt risk premium would increase between the 5 and 10 year terms.

- The AER evaluated the accuracy of the three curves by assessing which one minimised the average of the squared differences between the predicted yield for each BBB+ corporate bond in the sample, and the estimated actual yield. The yield estimates for bonds in the sample were obtained from Bloomberg, CBASpectrum and UBS; and
- The AER unduly restricted its attention to the sources listed above. The AER did not seek further estimates of yields for the bonds on issue, and nor did it attempt to obtain alternative estimates of fair value curves for Australian corporate bonds. The AER ignored other valuable sources of information, including data on bonds that have other credit ratings, and observations from floating rate notes (the yields from which can be transformed into equivalent fixed rates).

The AER claimed that its approach to testing both CBASpectrum and Bloomberg data was appropriate, and had been affirmed by the Australian Competition Tribunal.

In the pursuit of its approach, the AER found that the CBASpectrum curve was the most accurate. As such, the AER drew upon the debt risk premium that CBASpectrum predicted for 10 year BBB+ Australian corporate bonds.

The AER spurned the linear extrapolation methodology which had been developed by PwC. The technique was deemed to be inappropriate, and the AER opined that a proxy extrapolation using AAA fair yields would better estimate the 10 year BBB+ cost of debt.

9.8.4 UED response to the AER draft decision on the debt risk premium

The fundamental conclusion of the two expert economists engaged by the Victorian distributors is that the AER methodology is beset by errors. The two consultancy reports on the DRP that are appended to this submission (CEG, 2010g and PwC, 2010g) discuss the shortcomings of the AER's approach in detail, and suggest a raft of improvements.

On one level, the AER has attempted to answer the wrong question. As noted by CEG (2010g), the appropriate issue to consider is which of the fair value curves best estimates the 10 year BBB+ cost of debt (page 1 of CEG, 2010g). However, by applying the AER's test to the AER's sample of bond yields, the question effectively being asked is: Which curve best estimates the cost of debt for maturity of around 3.7 years?

The discussion in the sections below refers to some of the errors which afflict the approach taken by the AER. The explanations are not meant to be exhaustive, but provide an introduction to the more substantive issues which are addressed in detail in the expert reports (CEG, 2010g and PwC, 2010g). Descriptions are also provided of the ways in which the AER approach might be modified or enhanced.

9.8.4.1 Non-corresponding data set error

The primary reason the AER test is run with a sample of only 5 bonds is that the AER arbitrarily establishes criteria for sample selection that excludes information relating to:

- The estimated yields on bonds that are covered by one or two of UBS, CBASpectrum or Bloomberg but not all three.

- The estimated yields on BBB+ floating rate bonds (once swapped into an equivalent fixed rate yield).
- The estimated yields on bonds that do not have a BBB+ rating (such as BBB or A- rated bonds); and
- The estimated yields on bonds that are issued in Australia by foreign companies.

The exclusions are completely unjustified, as discussed by CEG (2010g). Information on longer dated bonds is clearly relevant to any assessment of the correct question, namely what is the best estimate of the BBB+ cost of debt at 10 years? While the long maturity BBB and A- bonds are not BBB+ rated, they are rated very close to BBB+ and they have the vital advantage that their remaining duration is much closer to ten years than is the term to maturity on the bonds in the AER sample. The bonds chosen by the AER are BBB+ rated but do not have maturities close to 10 years.

More broadly, the AER has failed to consider a wider range of sources of information. By restricting its attention to only the Bloomberg and CBASpectrum fair value curves, and the limited number of BBB+ rated Australian corporate bonds on issue, the AER has deliberately omitted other potentially useful sources of information. These alternative data sources could assist in improving the estimate of the debt risk premium that is commensurate with prevailing conditions in the market' for a 10 year BBB+ Australian corporate (fixed rate) bond.

The AER's sole pre-occupation with Bloomberg and CBASpectrum is difficult to justify owing to the lack of transparency surrounding the manner in which the services establish their debt risk premiums. There are also explicit disclaimers associated with their estimates and, in the case of CBASpectrum, a statement that the data service draws upon historical information and is focussed mainly on producing relative yield estimates and is therefore not 'fit for purpose'. PwC (2010g) also believes that the AER should have regard to other estimates of 'fair value' curves for Australian corporate bonds, and should concentrate particularly on a curve that is less opaque (in terms of the details of its construction) and more fit for purpose.

9.8.4.2 The incorrect period error

The AER has incorrectly assessed whether the current yield on the DBCT bond is an outlier by comparing its average yield since January 2009 with the average yields on the other bonds in the sample. The only correct test of whether the DBCT yield is currently an outlier is a test applied to the current yield. In contrast, the AER's test is equivalent to assessing whether a river is currently in flood by looking at the average level of the river over the past year. If the river was in flood in the first half of the year then the AER test would be prone to determining that it is still in flood even if it currently has below average water flow.

CEG (2010g) has shown that the DBCT yield estimated by UBS declined significantly in October 2009. By averaging over the period from January 2009, (which covers the period before the structural break occurred), the AER has derived an upwardly biased estimate of the current yield. Consequently, the AER's test cannot be used to provide a firm, unambiguous indication of whether the current yield on the DBCT bond results in it being classed as an outlier.

9.8.4.3 Failure to use the right sample error

The AER test also commits an error by comparing the DBCT yield to the yield on only the five other bonds in its sample. The AER sample of fixed coupon BBB+ bonds is so small that there is no way of establishing - with any measure of statistical confidence - that a difference between the yield on the DBCT bond and the AER sample is due to something abnormal about the DBCT bond or something abnormal about the AER sample.

CEG (2010g) has identified two bonds with very similar maturities to the DBCT bond (5.6 and 6.4 years versus the 6.1 year maturity for the DBCT bond). These bonds were issued by Melbourne Airport and Adelaide Airport, and have the closest maturities to the DBCT bond of all bonds in the sample chosen by CEG.

The Melbourne Airport and Adelaide Airport bonds are highly suitable for a comparison to the DBCT bond because they have the same average credit rating (one is BBB and one is A-), and also share an almost identical average maturity to the DBCT bond. Notably, the two bonds also have similar yields. Unless the Melbourne and Adelaide Airport bonds are outliers themselves, it would be very difficult to conclude that the DBCT bond is an outlier.

In the Victorian Draft Decision, the AER exempted the DBCT bond from its sample erroneously. The choice of the pool of bonds that is used to estimate the DRP of the BBB+ bond at a term of 10 years is clearly a pivotal issue. PwC (2010g) has examined a sample of 5 BBB+ bonds with more than 2 years to maturity. In contrast to the AER's practice, PwC has included the DBCT bond for the following reasons:

- It is the longest dated bond in the BBB+ rating category (which should raise the standard of proof required to reject it).
- The AER's reasons for rejecting the DBCT bond as an outlier are not persuasive (for example, the AER does not know where a bond with DBCT's characteristics should be trading in the current market).
- Recent pronouncements by Standard & Poor's confirm its BBB+ rating; and
- While the DBCT bond is only followed by a few institutions, implying that the yield estimate is likely to be more uncertain, this should not invalidate its inclusion.

9.8.4.4 Failure to investigate how the debt risk premium should increase beyond five or six years

The AER has, at best, only tested the respective fair value curves up to a term of five years (this being the term to maturity of the longest dated bond, if the DBCT bond is excluded). The AER has also merely assumed that the debt risk premiums predicted by the CBASpectrum service are 'accurate' beyond a duration of five years.

At the same time, however, the AER has acknowledged that it does not know how the CBASpectrum service predicts yields for bonds for terms to maturity which surpass those available from the input data. There are many aspects of the CBASpectrum and Bloomberg methodologies which are not known, because of their proprietary nature. The AER has simply relied upon a presumption that the extrapolation method followed by CBASpectrum is correct. Moreover, the AER has not tested whether the increase in the debt risk premium between 5 and 10 years, that is predicted by CBASpectrum, is reasonable against other evidence.

PwC (2010g) has reported that during the reference period (the 30 business days from 19th April to 31st May, 2010), the CBASpectrum BBB+ debt risk premium increased by only 21 basis points when moving along the curve between 5 and 10 year terms. In contrast, the Bloomberg AAA band debt risk premium increased by 83 basis points. PwC (2010g) has also observed a more pronounced gradation in the debt risk premium for two Telstra A-rated bonds with terms of 5 and 10 year terms respectively. As at the 2nd July 2010, the DRP rise between the 5 and 10 year duration Telstra bonds varied from 56 to 84 basis points, depending upon the data provider. Against these benchmarks, the prediction by CBASpectrum of a 21 basis point increase in the debt risk premium between 5 and 10 year durations is implausibly low.

9.8.4.5 Maintaining a narrow focus on squared errors and not testing whether the predicted yield is downwardly biased

As has been mentioned, the AER chooses a fair value curve by applying a minimum sum of squared errors test to the gap between observed bond yields and fair value yields for the same class of bonds. An intrinsic weakness of this method is that it does not provide information about whether the relevant fair value curve will systematically under- or over-estimate the underlying yield data. Thus, by directing its attention to only this measure of accuracy, the AER has not investigated whether there is a material bias in its estimate of the debt risk premium.

PwC (2010g) has reported that when the DBCT bond is included in the sample, all of the curves systematically understate the observed debt margins (with the degree of downward bias greatest in the case of CBASpectrum). Even if DBCT is excluded from the empirical analysis, the CBASpectrum curve systematically understates the debt risk premium if estimates of bond yields are taken from both Bloomberg and CBASpectrum data providers.

An allowed debt risk premium which, by virtue of its design and application, systematically understated the required premium would not satisfy the requirements of the NER and the NEL. This is because the DRP would not generate a return that is 'commensurate with prevailing conditions in the market' and it would, simultaneously, not give the businesses an opportunity to recover 'at least' their efficient costs.

9.8.5 Calculation of the DRP for the draft decision averaging period

Following advice from PwC and CEG, UED has devised a three-step method for estimating the DRP which corrects for the errors identified with the AER's method and its application.

- Step one: Test the Bloomberg and CBASpectrum services in isolation - examine whether the bond yield estimates that are produced by each service are likely to represent prevailing conditions in the market for funds. If not, then that service should not be used. This is an integrity test.

- Step two: This is a test of predictive accuracy. Examine the relative merits of Bloomberg and CBASpectrum services - assess which service provides the best estimate of the DRP for a 10 year BBB+ bond possible in the circumstances by answering the following two questions:

  - Which service provides the better explanation of the yields on the bonds that are on issue?

- What is the most appropriate method for extrapolating yield estimates for bonds with maturities longer than the bonds that are on issue?

- Step three: Estimate the DRP using the preferred service from step two – specifically, estimate the DRP on 10 year BBB+ rated bonds by:
  - if CBASpectrum is preferred, using the fair value yield for 10 year BBB+ corporate bonds
  - if Bloomberg is preferred, extrapolating the BBB-band fair value curve from six years out to 10 years using the Bloomberg AAA fair value curve[81].

Step one involves three tests and step two has three stages, which are described in more detail below.

9.8.5.1 Step one—three tests

Under step one, UED proposes three tests of the Bloomberg and CBASpectrum services:

1. Divergence in bank opinions - does the coefficient of variation of bank feeds into Bloomberg for the Australian corporate bonds, of greater than three years duration, that are considered for Bloomberg's fair value curve exceed 0.05?
2. Divergence of fair value yield from the bank opinions - does the average value of the difference between the Bloomberg or CBA Spectrum yield estimate and the mean of bank feeds for the Australian corporate bonds, expressed as a percentage of the yield, exceed +/- 2.50 per cent?
3. Divergence of fair value curve from yield estimates - does the average value of the difference between Bloomberg's (CBA Spectrum's) fair value curve and the Bloomberg (CBA Spectrum) bond yield estimate, expressed as a percentage of the bond yield estimate exceed +/- 4.00 percent?

9.8.5.2 Step two—three stages

Under step two, UED proposes three stages:

1. Select a sample of bonds - source yield estimates for a sample of BBB+ rated bonds that meet certain criteria. This is similar to step one of the AER's method. Here, outlier testing should:
   - consider a range of information sources, such as the opinions of credit rating agencies
   - compare to the relevant sample of bonds and data from other sources, such as the Royal Bank of Scotland, UBS, Bloomberg and CBASpectrum

[81] In this case, the debt margin on 10 year bonds is calculated as follows:

$$\mathrm{DRP(BBB)}_{10yr} = \mathrm{DRP(BBB)}_{6yr} + \left(\mathrm{DRP(AAA)}_{10yr} - \mathrm{DRP(AAA)}_{6yr}\right).$$

  - apply to UED's actual averaging period
  - not apply the Chow test, which is only relevant in identifying structural breaks
  - consider the true slope of the bond's DRP at different terms to maturity

2. Test for accuracy and bias of curves against sample - test the accuracy and bias of the respective fair value curves in predicting the yields on the sample of bonds with the most accurate fair value curve:
   - test for accuracy, by comparing the weighted sum of squared errors obtained by running the calculations associated with each service
   - test for bias, by comparing the (simple) average error associated with each service, consistent with the practice of regulators and advisors prior to the global financial crisis. This procedure is documented in PwC (2010c).
3. Select the most appropriate curve - choose the most accurate fair value curve as the basis for determining the observed, annualised Australian benchmark rate for corporate bonds with a BBB+ credit rating and a maturity of 10 years. This necessarily requires testing of the extrapolation used to get from five and six years out to 10 years by making comparisons with other data sources, such as:
   - the DRP observed in bonds of five and 10 year terms issued by a single company
   - the DRP observed in the Bloomberg AAA curve between five and 10 years
   - the movement in DRP between zero and five years in the same curve
   - the DRP implicit in longer maturity floating rate BBB+ rated bonds and fixed rate A- and BBB rated bonds
   - DRP estimates from market practitioners.

UED's method rectifies the errors with the AER's method by:

- testing for both bias and accuracy of the CBASpectrum and Bloomberg curves
- analysing the extrapolation implicit in the CBASpectrum BBB+ fair value curve, as well as the explicit extrapolation of the Bloomberg BBB fair value curve
- correctly testing for outliers by comparing a more relevant sample of bonds, not relying on the Chow test and recognising the opinions of credit rating agencies
- comparing the DRP estimate for a 10 year BBB+ rated Australian corporate bond to a wider range of data.

As a result, UED considers that its method produces an estimate of the DRP that better satisfies the requirements of the NER.

9.8.6 Results of the DRP calculation

The application of the UED method to its reference period results in a DRP estimate of 4.28 per cent for 10 year BBB+ rated Australian corporate bonds. UED considers that this estimate is the best available in the circumstances and is commensurate with prevailing market conditions. The reference period covers the 30 business days from 19th April to 31st May, 2010 inclusive.

The aforementioned value of the DRP has been obtained by reading off the Bloomberg BBB band fair value curve at 6 years, and then extending the estimate beyond that point using the change, from 6 to 10 years, in the debt risk premium that was observed under the Bloomberg AAA fair value curve. PwC (2010g) has only used the Bloomberg BBB band fair value curve out to 6 years because of limitations about the curve's accuracy. According to PwC (2010g), the accuracy is in terms of the test of the curve against BBB+ Australian corporate bonds on issue.

PwC (2010g) has reported that the Bloomberg BBB band fair value curve provides a more accurate prediction of the estimates from different providers of the yields on Australian BBB+ corporate bonds than the alternatives currently on offer from the AER, (namely the CBASpectrum BBB+ fair value curve, and an average of the Bloomberg BBB band and CBASpectrum curves).

PwC (2010g) has also found that the tests which were applied in the context of the November 2009 report on the internal integrity of the Bloomberg estimation process continue to be passed. The tests were discussed in PwC (2009k). PwC (2010g) has therefore concluded that the problems which afflicted the Bloomberg service during the worst of the global financial crisis are no longer present. In contrast, the tests show that CBASpectrum's estimates of the yields for some of the bonds currently on issue are some distance from the opinions of other financial institutions. A logical conclusion, therefore, is that its fair value curve should not be used to set a debt risk premium for regulatory purposes.

PwC (2010g) has used the AER's preferred method to extrapolate the debt risk premium beyond the 'useable' part of the relevant fair value curve. The AER's approach uses the Bloomberg AAA band fair value curve, which was producing debt risk premium estimates out to 10 years during the reference period. The use of the AER's techniques at this juncture has been driven by analytical convenience and should not be construed as demonstrating a full endorsement of the particular method. PwC (2010g) has advised that the choice of extrapolation method does not have an economically material impact at this time.

In summary, **PwC reported that:**

- The Bloomberg fair value curve passes the tests under step one.
- The DBCT bond is not an outlier, and in fact, CBASpectrum's estimate of the yield on this bond may actually be the outlier (pages 10 to 13).
- With the DBCT bond included in the sample, the Bloomberg BBB band fair value curve is more accurate and has less bias than the CBASpectrum BBB+ fair value curve.
- CBASpectrum gives an implausibly low estimate of the DRP for 10 year BBB+ rated corporate bonds when a comparison is made with other sources, including an expert report from market practitioner Mr. Terry Toohey (pages 35 to 37).

Furthermore, CEG (2010g) finds, in the context of UED's averaging period, that:

- The DBCT bond is not an outlier, even if the sample of relevant bonds is restricted to only include the six bonds which the AER used in its draft decision in the course of its assessment of whether the DBCT bond was an outlier (pages 34 to 45).

- The information on long maturity bonds clearly supports the selection of the fair value curve that is highest at 10 years, namely, the Bloomberg BBB fair value curve (pages 46 to 51).

In view of these findings, PwC (2010g) recommended the use of the Bloomberg BBB-band fair value curve, which was extrapolated using the Bloomberg AAA fair value curve. PwC estimated the DRP of 4.28 per cent after drawing upon the results which are summarised below in Table 9-4.

Table 9-4: DRP using Bloomberg's 6 year DRP and 6-10 year AAA curve

Details	Source	Average yield / DRP
A. Yield on five year BBB rated bonds	Bloomberg	8.84%
B. Yield on five year CGS	RBA	5.37%
C. Yield on seven year BBB rated bonds	Bloomberg	9.43%
D. Yield on seven year CGS	RBA	5.53%
E. DRP of five year BBB rated bonds	Calc = (A) – (B)	3.46%
F. DRP of seven year BBB rated bonds	Calc = (C) – (D)	3.90%
G. DRP of six year BBB rated bonds	Calc = ((C)+(D))*0.5	3.68%
H. Yield on five year AAA rated bonds	Bloomberg	6.16%
I. Yield on seven year AAA rated bonds	Bloomberg	6.63%
J. DRP of five year AAA rated bonds	Calc = (H) – (B)	0.79%
K. DRP of seven year AAA rated bonds	Calc = (I) – (D)	1.10%
L. DRP of six year AAA rated bonds	Calc = ((J)+(K))*0.5	0.95%
M. Yield on ten year AAA rated bonds	Bloomberg	7.19%
N. Yield on ten year CGS	RBA	5.65%
O. DRP of ten year AAA rated bonds	Calc = (M) – (N)	1.54%
P. Proposed DRP on 10 year BBB+ rated bonds	Calc = (G) + (O) – (L)	4.28%

Source: Appendix B of PwC (2010g). Reliance has been placed on Bloomberg's 6-year DRP and Bloomberg's 6-10 year AAA curve.

9.9 Value of imputation credits (gamma)

9.9.1.1 Rule requirements

The National Electricity Rules (NER) require an assumption regarding the utilisation of imputation credits to calculate the cost of corporate income tax of a DNSP for each regulatory year. Clause 6.5.3 of the NER requires that the cost of corporate income tax be calculated in accordance with the following formula:

$$ETC = (ETI \times r)(1 - \gamma)$$

where:

ETI is the estimated taxable income for the regulatory year;

r is the statutory income tax rate; and

γ (gamma) is the assumed utilisation of imputation credits.

Gamma is conventionally estimated using the Monkhouse formulation (Monkhouse, 1993) under which gamma is the product of:

- the **payout ratio**, which is the share of created imputation credits that are distributed to shareholders; and
- **theta**, which represents the market value of imputation credits as a proportion of their face value.

The AER has conformed to the gamma formulation shown above, apparently relying also on Monkhouse (1997).

The NER also require the AER to carry out a review of rate of return parameters every five years and issue a Statement of Regulatory Intent (**SORI**) adopting values, methods and credit rating levels for DNSPs or specified classes of DNSPs[82]. A distribution determination to which a SORI is applicable must be consistent with the SORI unless there is "persuasive evidence justifying a departure, in a particular case, from a value, method or credit rating level set in the statement"[83]. In determining whether a departure from a SORI is justified in a distribution determination, the AER is required to consider[84]:

- The criteria on which the value, method or credit rating level was set in the SORI (**the underlying criteria**); and
- Whether a material change in circumstances since the date of the SORI, or any other relevant factor, now makes the value, method or credit rating level set in the SORI inappropriate.

[82] NER, clause 6.5.4

[83] NER, clause 6.5.4(g)

[84] NER, clause 6.5.4(h)

As required by the NER, the AER concluded its first review of rate of return parameters on 1st May 2009 and issued its SORI. The SORI set a value for gamma of 0.65. In the decision document accompanying the SORI, (AER, 2009e4), the AER justified the value on the grounds that:

a) An assumed payout ratio of 100 per cent appeared reasonable and consistent with the Officer framework (page 466, AER 2009e4);

b) The value of theta should be 0.65, which was chosen as the midpoint of the values produced by dividend drop-off studies and taxation studies. The only dividend drop-off study relied upon by the AER was the study by Beggs and Skeels (2006), which produced an estimate for theta of 0.57. The AER did not place any weight on the more up-to-date findings of the SFG (2009) dividend drop-off study, which produced substantially lower estimates of theta. The AER relied on tax studies to provide an "upper bound" for theta. It derived an upper bound of 0.74 as the mid-point of the range of values from the tax studies (the range being 0.67 to 0.81).

The SORI marked a significant departure from previous regulatory practice in respect of the value of gamma. Prior to the SORI, the ACCC and various state regulators had all adopted a value for gamma no greater than 0.5 (in some cases a value for gamma below 0.5 had been adopted). Table 10.2 in the final decision for the WACC review (AER, 2009e4) shows that jurisdictional regulators in NSW, Queensland, Victoria, South Australia, Tasmania, and the ACT had settled upon gamma values of 0.5 or less than 0.5.

The underlying criteria used by the AER in its SORI were based on the revenue and pricing principles in section 7A of the National Electricity Law, and the factors to which the AER is required to have regard under clause 6.5.4(e) of the NER. In the Victorian draft decision, the AER has stated that its underlying criteria were:

- The need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services.
- The need to achieve an outcome that is consistent with the national electricity objective.
- The need for persuasive evidence before adopting a value or method that differs from the value or method previously adopted; and
- The relevant revenue and pricing principles, which are:

- Providing a service provider with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services and complying with a regulatory obligation or requirement or making a regulatory payment.
- Providing a service provider with effective incentives in order to promote efficient investment, and
- Having regard to the economic costs and risks of the potential for under and over investment.

9.9.1.2 AER Review of cost of capital parameters

As its contribution to the WACC review conducted by the AER in early 2009, the Strategic Finance Group (SFG) submitted an empirical analysis of theta based on a dividend drop-off approach. The SFG study, (SFG, 2009) applied econometric methods which had previously been used by Beggs and Skeels in an earlier research project (reported in Beggs and Skeels, 2006).

The AER dismissed the SFG study, and disregarded its results, despite the appropriateness of the techniques employed. In its final decision on the WACC review (AER, 2009e4), the AER claimed that:

> Despite the advantage of providing more up-to-date estimates (i.e. to 2006), the AER has concerns regarding the reliability of the SFG study, and considers that correction of identified deficiencies would likely have a material impact on the results. Accordingly while the AER has given full consideration to the SFG study, limited weight has been placed upon theta estimates generated by the SFG study for the purposes of this final decision.

9.9.1.3 Regulatory proposals by UED and the other Victorian distributors

The Victorian electricity distributors all proposed a departure from the value of gamma set in the SORI. Jemena Electricity Networks (JEN) proposed a value of 0.2, while the other distributors proposed a value of 0.5.

The proposals by the distributors argued that there was persuasive evidence justifying a departure from the SORI value for gamma. In particular, there appeared to be a number of weaknesses in the reasoning adopted by the AER in its WACC review. The AER also lacked objectivity about the manner in which it applied the criteria set out in the SORI. The AER was supposed to use the criteria as a guide to making decisions about WACC parameter values.

In addition, there was evidence before the AER of a material change in circumstances since the date of the SORI which meant that the gamma value of 0.65 was no longer appropriate.

Specifically, in relation to the payout ratio, the distributors cited similar concerns to those expressed by ETSA Utilities in the South Australian distribution price review process. The distributors referred to the expert evidence of Professor Robert Officer and tax lawyer, Peter Feros, who both rejected the assumption that all imputation credits are distributed to shareholders. Their analyses and testimony are reported in Officer (2009f) and Feros (2009f), respectively. The distributors also noted the findings of the Hathaway and Officer (2004k) study which had estimated a payout ratio of 0.71. JEN further noted the conclusions of a report by Synergies, in which it was stated that the payout ratio, calculated from tax statistics over the period from 2003 to 2007, had an average value of 0.66 (page 9, Synergies, 2009e).

The distributors argued that the value of theta should be less than that set in the SORI, and submitted evidence to support this claim. The key evidence relating to the value of theta was a report by Professor Skeels in which he reviewed an SFG study, (SFG, 2009b), which had been prepared and submitted for the AER's WACC review. Professor Skeels noted that the AER's arguments against the use of the SFG study were "unconvincing" and were in fact nothing more than allusions to potential problems which were amenable to further investigation. Skeels conducted such an investigation by posing a number of questions which were answered by SFG after SFG had undertaken further analysis (see Appendix I of

Skeels, 2009h). Skeels was then able to report that the study results were convincing. He concluded as follows (see page 30 of Skeels, 2009h):

> This leads me to consider that their [SFG's] estimate of theta of 0.23 is the best such estimate currently available for Australia. It might be argued that their methodology does not perfectly replicate that of Beggs and Skeels (2006) and that the remaining differences may downwardly bias the estimates provided by SFG in Appendix I. I am not one who shares that view as I think their analysis is now compelling. However, if one was to take that view then I think that a very strong case could be made for the true value of theta to lie somewhere between the SFG estimate of 0.23 and the Beggs and Skeels (2006) estimate of 0.57, and in all probability to lie towards the lower end of that range. Any higher value for theta seems completely implausible, both in terms of the empirical evidence presented and in terms of the theoretical arguments underpinning them.

The analysis and opinions presented by Associate Professor Skeels in his independent report addressed all of the following criteria: Statistical rigour, independent verification, methodological rigour, and the use of the largest available data set for the post July 2000 period. Accordingly, UED's original Regulatory Proposal argued that this new evidence:

- Constitutes persuasive evidence which justifies, in accordance with Clause 6.5.4(g) of the Rules, departure from the gamma value specified in Clause 3.8 of the SORI; and
- Demonstrates a material change in circumstances relating to the estimation of the gamma value since the SORI was issued in May 2009, so that the gamma value specified in that statement is inappropriate, in accordance with the provisions set out in Clause 6.5.4(h) of the Rules.

UED's original Regulatory Proposal submitted that had this evidence been available to the AER at the time of its WACC final decision, the AER would have determined that:

- the lower bound estimate of theta is not 0.57; but rather
- the correct lower bound estimate of theta is 0.23.

JEN also noted the findings of a tax study by Synergies in which it was estimated that investors typically only utilised 35 per cent of the credits that they receive (Synergies, 2009e).

9.9.2 AER draft decision on gamma

The AER Draft Decision rejected the distributors' proposals for a departure from the SORI value of 0.65. The Draft Decision drew on two new reports commissioned by the AER:

- An opinion piece prepared by Associate Professor John Handley of the University of Melbourne (Handley, 2010c); and
- A report by Professor Michael McKenzie and Associate Professor Graham Partington on behalf of the Securities Industry Research Centre of Asia-Pacific (McKenzie and Partington, 2010c).

In relation to the payout ratio, the AER stated that the evidence presented by JEN had already been considered as part of the WACC review. The AER repeated its contention that a payout ratio of 100 per cent is consistent with the Officer WACC framework, which assumes that cash flows occur in perpetuity and are therefore fully distributed at the end of each period. The AER also asserted that even where imputation credits are retained, they will still hold value. The AER noted and agreed with the advice of its experts (including McKenzie and Partington) that the actual payout ratio is likely to be between 70 per cent and 100 per cent. Nonetheless, the AER adopted a value at the top of this range, noting that "the assumption of a 100 per cent payout ratio simplifies the framework for estimating gamma" (page 420, AER 2009e4, and page 537, Victorian Draft Decision).

In relation to theta, the AER stated in its Draft Decision that it does not consider the report by Professor Skeels to represent persuasive evidence. The AER noted that although Professor Skeels appeared to address a number of the AER's concerns with the SFG study, there were still a significant number of issues which demonstrated that SFG's estimates were likely to be unreliable.

After reviewing the expert reports which it had commissioned, the AER expressed the following concerns:

- McKenzie and Partington's analysis demonstrates that SFG's regression results are likely to be affected by multicollinearity and, as a result, the values of imputation credits are likely to be downwardly biased (pages 542-545 of the Draft Decision).
- The SFG study has problems with consistency in parameter estimation and data reliability remains an issue.
- SFG's use of the Cook's D-statistic is likely to be less reliable than a filtering method which employs "economic criteria" (page 548 of the Draft Decision). McKenzie and Partington (page 50, 2010c) suggested that economic criteria should form part of an *ex ante* approach to screening for outliers. The AER has claimed that Beggs and Skeels (2006) adopted "economic criteria", even though Beggs and Skeels (2006) did not explicitly use such a phrase and did not allude to an economic justification.
- The number of zero and negative drop-offs in SFG's data set is abnormally high.
- The AER notes the conclusions of the Handley Report that taxation studies may provide a reasonable estimate of the upper bound for theta.

In short, the AER has rejected the empirical estimate of theta (0.23) derived by SFG Consulting using dividend drop-off analysis. SFG made numerous refinements to its approach in response to the AER's comments subsequent to the ETSA Draft Decision, however the AER has refused to concede that SFG has arrived at a valid and defensible result. SFG also undertook extensive auditing and checking of its data.

The AER estimate of theta is based on an average of the 'lower' and 'upper' bound estimates derived, respectively, from the Beggs and Skeels (2006) dividend drop-off study and the Handley and Maheswaran (2008c) analysis of tax data for foreign investors in Australia. The Beggs and Skeels (2006) estimate is 0.57, obtained via econometric analysis of stock price changes. The Handley and Maheswaran (2008c) estimate is calculated as an average of the upper values (0.67 and 0.81) obtained from an evaluation of tax statistics over two time periods. The AER 'upper bound' is therefore 0.74. The overall estimate of theta put forward by the AER is 0.65 (which is evaluated as the mean of 0.57 and 0.74).

The AER combines its estimate of theta (0.65) with a presumed payout ratio of 100 per cent to derive an overall value for gamma of 0.65.

UED's response to the AER on gamma is discussed below in section 9.10. The section addresses each of the arguments made by the AER in its Draft Decision and also discusses the accompanying expert reports.

9.10 UED's response to the AER's Draft Decision on gamma

9.10.1 UED's response to the AER draft decision on the distribution rate

In their initial regulatory proposals, the distributors presented the AER with a considerable array of evidence to substantiate the case for a departure from the 100 per cent payout ratio. The evidence was comprised of the report by Hathaway and Officer (Hathaway and Officer, 2004k) and expert evidence from Professor R.R. Officer (Officer, 2009f), and Mr Peter Feros (Feros, 2009f). In addition to the above, UED notes that the AER's own advisers have made statements to the effect that the payout ratio is less than 100 per cent.

McKenzie and Partington (2010c) refer to the actual payout ratio as being "about 70 per cent" (page 27), in line with the findings of Hathaway and Officer (2004k), and more recently NERA (pages 6-7 of NERA, 2010a). McKenzie and Partington go on to conclude that the appropriate payout ratio for the purposes of estimating gamma should lie between 70 per cent and 100 per cent, since undistributed credits will have at least some value. It is noted that the AER implicitly assumes that there is either a 100 percent payout (an assumption which McKenzie and Partington consider to be unrealistic), or else undistributed credits have the same value as distributed credits. As reported by McKenzie and Partington (on page 26 of their report):

> The AER makes the assumption that there is a 100 percent payout of imputation credits. Taken literally, this is clearly incorrect. However, we view the 100 percent payout assumption as simply a convenient step designed to allow for the value of undistributed franking credits when computing gamma. It is equivalent to saying that undistributed franking credits have the same value as distributed franking credits. In principle, this is likely to overstate the value of the undistributed credits, but it is not clear by how much.

McKenzie and Partington (2010c) also consider the assumption that undistributed and distributed credits hold the same value to be unrealistic. They note (on page 25 of their report) that:

> Clearly, undistributed credits will be discounted relative to distributed credits…

The Handley Report (Handley, 2010c) reaches a similar conclusion that the payout ratio lies between 70 per cent and 100 per cent. Associate Professor Handley also considers that the AER's assumption of a full payout is unrealistic, in view of the empirical evidence which demonstrates a substantially lower payout, and Handley's own acknowledgement that investors are likely to discount the value of undistributed credits. Handley notes that a discount rate should be applied to retained credits, and that there will be a retention period (page 33, Handley, 2010c).

Associate Professor Handley notes:

> An assumption that all credits are distributed in the period in which they are created will likely overstate the value of gamma.

The AER's expert advisers therefore seem to agree that that the payout ratio is less than 100 per cent. They have effectively conceded that the assumption of a 100 per cent payout ratio will result in gamma being over-stated. The only issue which the experts have considered but have been unable to resolve is the extent to which the payout ratio should be below 100 per cent, to reflect the lower value of undistributed credits. For the reasons set out below, UED considers that little value should be assigned to undistributed credits, and that the payout ratio should be significantly below 100 per cent.

The AER's 100 per cent distribution rate rests on two propositions which haven't been explicitly stated, but have nonetheless been assumed:

- Firstly, that undistributed credits will eventually be distributed; and
- Secondly, that there is no difference in value between distributed and undistributed credits.

In relation to the first assumption, the expert evidence of Mr Feros (Feros, 2009f) demonstrates that there are a number of legal and regulatory impediments to the distribution of retained credits. Furthermore, there are practical impediments to distribution since companies will build up large amounts of retained credits as they only distribute, on average, around 70 per cent of those created in each year. Over time, companies will need to distribute more credits than are actually created in order to distribute retained credits. The 70 per cent distribution rate is an average, and, over time, businesses do not generally distribute more credits than are actually created. These results are made apparent by the high value of retained credits revealed in the Australian Taxation Office statistics. The Handley Report (page 33, Handley 2010c) notes that the aggregate balance of retained imputation credits at the end of June 2007 totalled almost $150 billion. McKenzie and Partington (2010c) have noted a tendency for franking account balances to increase over time (page 27) which, in itself, lends credence to the finding that businesses do not generally distribute more credits than are actually created.

The AER does not have any empirical evidence to support its assumption that retained credits will be distributed soon after retention. The AER has expressed uncertainty about the length of time for which firms retain imputation credits and has also stated that it is unaware of any empirical research about the retention period (page 537 of the Victorian Draft Decision). The AER has merely assumed that retained credits will be paid out over one to five years, when there is in fact no reason to believe that the payout period would be of similar duration to the regulatory period. There is also no basis for the supposition that the payout period would coincide with the regulatory period. Furthermore, the AER has chosen to ignore the evidence from Peter Feros (Feros, 2009f), and from ATO statistics, which demonstrates significant constraints on the ability of companies to distribute retained credits in a timely manner.

Associate Professor Handley has argued that there are ways in which the value of retained credits may be "unlocked", including through off-market buy-backs and dividend re-investment plans. In Handley (2009d), he also made the claim (on page 8) that:

> It is unreasonable to assume that such a build up of [imputation] credits would not (eventually) attract the attention of investors, investment bankers and or potential corporate raiders.

However, the use of mechanisms such as off-market buy-backs and dividend re-investment plans is relatively limited, and transactions of this nature do not have a significant impact on the overall balance of retained imputation credits. These mechanisms are already being employed at present, and their application is reflected in the results from distribution rate studies, including those of Hathaway and Officer (2004k) and NERA (2010a). The Hathaway and Officer (2004k) and NERA (2010a) studies consider the total amount of credits distributed by any means (including the methods to which Handley refers) as a share of credits created.

With respect to the second assumption made by the AER, there appears to be general recognition (including among the AER's experts) that investors will discount the value of undistributed credits. The extent to which discounting occurs will depend on investors' discount rates and length of time taken for retained credits to be distributed (as discussed above). Even where the discount rate is low, the discounted value of retained credits will be very small if it takes a long time for retained credits to be distributed.

The evidence about the distribution rate of franking credits implies that there is a certain rate of retention of credits by companies. However, as mentioned previously, there are also constraints on distribution once the credits have been retained. UED therefore believes that investors would heavily discount the value of retained credits. Therefore, the payout ratio should closely reflect the actual distribution rate of 70 per cent which is supported by the empirical evidence and recognised by the AER's expert advisers.

Importantly, it should be noted that, contrary to the claims made by the AER in its Draft Decision, a payout ratio below 100 per cent would not be inconsistent with the Officer CAPM framework. Professor Officer himself has stated that the Officer framework does not delve into the payout ratio (pages 2, 3 and 6 of Officer, 2009f). According to Officer (2009f):

> The Officer (1994) paper implicitly assumes that the [value of the imputation credits] reflects the value of the credits at the time they are distributed which is consistent with paying them out immediately or them being subject to significant (even infinite) delays.

In the same paper, Officer(2009f), Professor Officer has further remarked that:

> As I have indicated above, my original paper (Officer, 1994) did not address the issue of a variable distribution, the paper's conclusions are consistent with an immediate or full payout of earnings or a delayed payment.

The Officer (1994) framework did not directly address the matter of the timing of the payout of franking credits, and therefore, in effect, made a simplifying assumption that credits would be valued at the time that they are distributed. While Professor Officer may not have considered incorporating retained earnings into his 1994 formulae, this does not mean that the formulae only apply to situations where the payout ratio is 100 per cent.

In academic analysis, simplifying assumptions are common and are not necessarily framed to reflect reality. However, there is no intention that the simplifying assumptions should somehow constrain or prevent economic models and analysis from being applied to real world situations.

The implication of a 100 per cent payout ratio would be that firms cannot grow from internal resources, and an assumption of this nature cannot be sustained in practice. Helpfully, Dr Hathaway has demonstrated (in Hathaway, 2010g3) that the Officer CAPM can accommodate firms which grow by earnings accretion, or from internally generated resources, and are therefore not paying out all of their cash flows as dividends, with the associated imputation credits (see pages 12-13 and 15-21 of Hathaway, 2010g3).

According to Associate Professor Lally, the Officer CAPM is one of a class of robustly derived tax-adjusted capital asset pricing models in which gamma (and, implicitly, also the payout ratio) has a variable value rather than an assumed fixed value (see Lally, 2000). Lally has further noted (in Lally, 2002, see page 18) that:

> Within the context of the Officer model, the [payout ratio] is firm specific. Variation across firms will arise from variation in the ratio of Australian company tax paid to Australian sourced "profits", and variation in the ratio of cash dividends to "profits".

Empirical methods provide better estimates of the payout ratio than hypothetical values, an argument which is strongly endorsed by Professor Stephen Gray (paragraph 28, SFG, 2010g):

> In particular, the distribution rate should be estimated using empirical data from the real world, rather than assuming a hypothetical value.

9.10.2 UED's response to the AER on the value of theta

9.10.2.1 Assessment of theta by the AER's consultants

In the Victorian Draft Decision, the AER has been unjustly critical of the SFG dividend drop-off study (SFG, 2009b). In contrast, the AER's own consultants have noted the limitations of empirical approaches to the measurement of theta more generally. In view of these limitations, McKenzie and Partington (2010c) recommend a balanced approach to the evidence on theta, taking into account all available sources of information. McKenzie and Partington (page 9, 2010c) state (with emphasis added here):

> Ex-dividend studies and taxation studies however, both have limitations. Ex-dividend studies have substantial measurement and estimation issues and they involve an analysis of trades in a restricted window. Taxation studies present results that apply across a broad sweep of investors, but they are subject to measurement problems (this has proven to be less of an issue since the introduction of the simplified tax system). Furthermore, the link between taxation statistics and the market value of imputation credits remains indirect. Therefore, neither type of study is likely to provide an accurate and definitive estimate of gamma on its own. **Given the uncertainty surrounding the estimates of gamma, we argue that it is preferable to consider evidence from multiple sources. This means considering results from both types of study and, where multiple studies of the same type are available, considering the results across these studies.**

McKenzie and Partington (page 3, 2010c) summarised this advice, which the AER did not follow in its Draft Decision, in even more explicit terms (with emphasis added here):

> Given the problems inherent in estimating gamma using either taxation or ex-dividend studies, we argue in favour of a balanced approach. Since the best estimation techniques are beset with problems, the most logical approach is to consider the evidence on balance across all available sources. In this respect, the AER's approach of considering both ex-dividend and taxation statistics has merit, but **we would recommend a broader range of studies to triangulate the evidence considered by the AER.**

In the Draft Decision, the AER appears to have largely ignored this advice from its own consultants. The AER has relied on just one dividend drop-off study, namely Beggs and Skeels (2006) while disregarding, and not drawing upon the results from, the more recent SFG study (SFG, 2009b). Moreover, the AER appears to have overlooked the deficiencies of the only tax study upon which it relies (Handley and Maheswaran, 2008c). The shortcomings of this taxation study and the AER's specific concerns with the SFG (2009) study are addressed in more detail below.

9.10.2.2 The use of taxation studies to derive estimates of theta

UED considers that tax studies should not be used to calculate the value of theta, because no inferences can be drawn from the data as to the value of imputation credits to investors. Tax statistics are generally only helpful for working out the distribution rate. If the AER is inclined to use studies based on tax statistics, then the findings of these studies should be interpreted with care, given the apparent problems with the data used.

9.10.2.2.1 Appropriateness of using tax studies

Tax research studies - including those upon which the AER relies - estimate the extent to which imputation credits are *used* by investors. The result of these studies is a ratio of credits redeemed in a given year to the number of credits created in that year. These studies provide limited information about the *value* of imputation credits to those investors that redeem them and should therefore not be used to calculate theta.

Tax studies would only be relevant to the value of theta if an assumption were made that the value of redeemed credits was equal to 100 per cent of their face value. If the value of these credits to redeeming investors was 50 per cent of their face value, then theta would be equal to 50 per cent of the redemption rate.

The AER's expert advisers do not claim that tax studies provide a reliable estimate of theta, only that these studies provide a reasonable upper bound. In other words, theta will be no higher than the estimates produced by the tax studies, but could be significantly lower.

Handley (page 15, 2010c) refers to the results of Handley and Maheswaran (2008c) and notes that the study provides an "upper bound" for theta, with the phrase having been applied in the sense of a theoretical maximum, rather than in the context of a confidence interval. McKenzie and Partington (page 9, 2010c) report that:

> ...the link between taxation statistics and the market value of imputation credits remains indirect.

These comments represent an acknowledgement by the AER's expert advisers that the redemption rate of imputation credits will only be a true reflection of the value of these credits to investors if an assumption is made that the redeemed credits are indeed fully valued. In practice an assumption of this nature cannot necessarily be sustained.

The notion of an indirect linkage between taxation statistics and the market value of imputation credits is supported by Dr Neville Hathaway, who, in a research report on taxation statistics, (Hathaway, 2010g2), makes an informed judgement that:

> ATO data give an overall measure of redeemed credits. The ATO data ought to give an upper bound for the value of credits. After all, the capital value estimate [from dividend drop-off studies] is a "pay now collect later" measure whereas the ATO data are a measure of the "collect" value.

UED considers that the AER should exercise caution and not take into account "upper bound" estimates from taxation studies which are, at best, indirectly linked to the value of imputation credits. In calculating theta, it is inappropriate to average these theoretical maximum values with the point estimates produced by dividend drop-off studies.

9.10.2.2.2 Risks associated with using tax studies

Notwithstanding the arguments against the use of tax studies (outlined above), if the AER maintains its view that these studies should be used, then it ought to be circumspect about interpreting the results. There are a number of issues with both the theoretical bases for these studies and the econometric techniques used.

The research paper relied on by the AER to derive its "point estimate"[85] for theta from tax statistics contains various qualifications and assumptions which should induce caution in interpretation. The study by Handley and Maheswaran (2008c) produces values for the redemption of imputation credits in a range of 0.67 to 0.81, from which the AER derives a mid-point of 0.74. However, Handley and Maheswaran (2008c) make a number of assumptions and qualifications in their study, which are not interrogated by the AER.

Most obviously, Handley and Maheswaran (2008c) do not empirically estimate the redemption rate for imputation credits for the post-2000 period. The authors in fact assume that all credits will be redeemed by individuals and funds over this period, while estimating the redemption rate for non-residents[86]. No justification is offered for this assumption, although there are allusions to "investor rationality"[87]. Nevertheless, the estimate of redemption rates for this period cannot form a basis for decision-making by the AER because the figure is based on assumption rather than empirical analysis. An assumed value of the overall redemption rate in the post-2000 period may explain why the estimate produced by Handley and Maheswaran (2008c) is substantially higher for 2001 to 2004, than it is for the previous decade (0.81 compared to 0.67).

Further problems are identified by Dr Hathaway in his expert report (Hathaway, 2010g1) on the Handley and Maheswaran (2008c) study. Dr Hathaway has discussed in detail the key limitations of this study including that:

- The results appear to be contrived as they are based on analyses of data that the authors themselves have created by their assumptions.
- Data has been averaged over periods of materially different tax regimes, potentially distorting the results; and
- The methodology used to combine data for different groups introduces the risk of double counting.

In the separate report on taxation statistics (Hathaway 2010g2), Dr Hathaway finds that the taxation data which underpins the Handley and Maheswaran (2008c) study appears to have unresolved imbalances. Dr Hathaway notes that there are significant unexplained discrepancies in the taxation data and he concludes that the data should not be relied on for making conclusions as to the value of theta. After much considered judgement and deliberation, Dr Hathaway wrote as follows (page iv, Hathaway 2010g2):

> Until [the] reconciliation [of the "missing" $48 billion of credits between tax data, FAB data and dividend data] has occurred or it can be explained to me how to account for those credits, I urge all caution in using ATO statistics for any estimates of parameters concerned with franking credits.

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85 Although, as noted above, the use of the term 'point estimate' for theta is erroneous, since the tax studies provide, at best, an upper bound.

86 Handley and Maheswaran (2008c), page 90. In the bottom panel of Table 4, the utilisation rate is set to 1 for individuals and funds for each of the years 2001-2004; (for earlier years, the utilisation rate takes a lower value).

87 Handley and Maheswaran (2008c), page 86

And (on page 16):

> Unfortunately there are too many unreconciled problems with ATO data for a reliable estimate to be made about theta and gamma. About the only consistent measure is the overall distribution fraction of 69%. This is the long term average estimate. The more recent estimate is 68%, the reduction caused by a change to the FAB being operated on a rolling tax paid basis. Gamma is the product of this distribution fraction and the value of a distributed credit, theta, and as theta is very unclear from the ATO data then so is gamma unclear.

In view of the numerous shortcomings described and documented by Hathaway (2010g1), the results of the Handley and Maheswaran (2008c) study can essentially be regarded as unfit for purpose.

9.10.2.3 UED comment on dividend drop-off studies

UED considers that the SFG dividend drop-off study (SFG, 2009b), updated for ETSA Utilities in January 2010 (SFG, 2010a), provides the most reliable and current estimate of theta. The econometrically determined estimate of theta, derived over the period from 1st July 2000 to 30th September 2006, is 0.2379.

The SFG study is more comprehensive than the Beggs and Skeels (2006) dividend drop-off study, the results of which the AER has used in its Draft Decision. The SFG study uses a dataset covering a much wider cross-section of businesses and also employs a longer time series of data, extending to a more recent period. Associate Professor Chris Skeels, a co-author of the Beggs and Skeels (2006) research paper, reported that the analysis by SFG constituted an empirically valid study of the dividend drop-off problem for Australia (page 5, Skeels, 2009h). Skeels affirmed that the SFG estimate of theta, obtained after a re-working of the results, represented the most accurate estimate currently available.

In a further response to the AER, (Skeels, 2010a), which was prepared in response to the ETSA Draft Decision, Skeels stated definitively, (on page 7), that:

> The AER correctly identified some shortcomings with the original SFG study. However, SFG have responded to the AER's concerns and, in my opinion, their revised results merit greater consideration than they have received to-date, especially as they are based on the most up-to-date and relevant data of any of the studies that have been considered.

UED agrees with the recommendation made by McKenzie and Partington (2010c) for a more "balanced approach" to the evidence from the available dividend drop-off studies. It is unreasonable for the AER to place so much weight on the findings of Beggs and Skeels (2006), whilst ignoring the more recent evidence from SFG (2009b and 2010a). Although the AER has expressed several concerns with the SFG (2009) study, these concerns would appear to be unfounded. Each of the AER's specific concerns in relation to the SFG study is addressed below. In general, the concerns expressed by the AER are either exaggerated or unwarranted.

Multicollinearity in dividend drop-off studies

The AER has argued that multicollinearity remains an issue in the SFG (2009b) dividend drop off study. However, the AER has failed to acknowledge that multicollinearity is no more of an issue for SFG than it is for Beggs and Skeels (2006). The criticisms by McKenzie and Partington (2010c) are generic to dividend drop off studies as a whole and not unique to SFG (2009b).

McKenzie and Partington (2010c) note that multicollinearity is a problem for dividend drop-off studies generally and therefore emphasise the importance of taking a balanced approach to the evidence:

> The final area of concern for dividend drop off studies relates to the econometric issues surrounding the estimation of the regression equations. In particular, the issue of multicollinearity dominates as there is a perfect linear relationship between the size of the cash dividend and the franking credit… We conclude that the problems inherent to dividend drop off studies only serve to reinforce our view that a logical approach to estimating gamma is to consider the evidence on balance across all available sources and not rely on any one individual source.

Despite this clear advice from McKenzie and Partington, the AER has concentrated on just one dividend drop-off study, making it the cornerstone of its overall derivation of theta. The AER has wrongly perceived that the Beggs and Skeels (2006) results are somehow immune from the sorts of issues which have characterised the estimation process and outcomes from the SFG study. However, the expert report commissioned by the AER demonstrates that there is nothing unique about Beggs and Skeels (2006) which might mean that its results should be used to the exclusion of all other results.

UED firmly believes that the AER's concerns about multi-collinearity in the SFG (2009b) study are overstated. The standard errors of the parameter estimates are not of sufficient magnitude to suggest that multicollinearity represents a material concern. Skeels (2010a) concluded his assessment by stating that there is no evidence that multicollinearity is a serious practical problem in either the Beggs and Skeels (2006) paper, or in the SFG (2009b) study.

Filtering and data quality

UED considers that proper filtering methods were applied to the dataset in the SFG study so as to exclude anomalous observations and to omit certain types of data where there were sound economic reasons for so doing. In January 2010, SFG conducted a rigorous sampling exercise which revealed, after a review of some 236 ASX announcements in relation to 150 observations, that there were negligible changes to the results previously reported by SFG. The evaluation and testing of the database was undertaken by Dr John Field, an independent statistician, who applied statistically robust sampling techniques to the task of interrogating the SFG database. The results of Field's work were reported in SFG (2010a).

The AER has reported that the results of the sampling test applied by Field imply that the number of "unacceptable" observations lies in a range of 6.2 to 16.7 per cent. While this may arguably be the case, the AER has given no consideration to the materiality of the "unacceptability" and its likely impact on the results. The simple fact of the matter is that removing observations which are uninfluential will have little impact on the results. SFG also adopted a modified version of the Cook's D procedure which removed influential and unreliable observations.

The AER opined that the sampling exercise served no useful purpose, however the procedure showed clearly that the removal of further observations had an immaterial effect on the regressions which were run, thus highlighting that SFG's results were both stable and robust. After a re-estimation of the equations following the removal of a handful of observations, there were small changes to parameter estimates at the third decimal point.

As a final observation, the SFG study has been subject to a much greater degree of scrutiny than the research paper by Beggs and Skeels (2006). In contrast to the situation with Beggs and Skeels (2006), the SFG data has been made available for comment and SFG has responded to any and all concerns raised by the AER. There has been no forensic analysis or comprehensive review of the Beggs and Skeels (2006) study. Although the research output was published in a peer reviewed journal, the review process would not have involved any testing of the model code and data. Another relevant consideration is that the paper was written to examine structural breaks in the tax system, and not to derive an estimate for theta *per se*. As previously noted, Skeels (2010a) has affirmed his view that the SFG estimate is currently the best available (page 8).

The Use of Cook's D statistic as a testing procedure

The criticisms in the Victorian Draft Decision surrounding the use of Cook's D Statistic seem unwarranted because the procedure was modified by SFG and Skeels, and a new set of results was reported in an appendix to Skeels (2009h). SFG amended the use of the Cook's D procedure so as identify the top one per cent of observations, and then only exclude those which were unreliable. This form of application is not arbitrary but is justified on economic grounds.

The AER has now claimed that the use of Cook's D-statistic may introduce a bias into SFG's analysis because it only excludes individually influential observations that are economically unreliable. The process does not identify groups of observations that are jointly significant. However, the AER has provided no examples of the types of observation which it may consider to be "jointly influential", and nor has it given an indication as to how this issue might manifest itself in the results. Hence, the AER has alluded to a possible issue, but has been unable to quantify the implications, and has also provided no evidence to support its assertions.

Skeels reviewed the modified approach to the use of the Cook's D Statistic (Skeels, 2009i) and remarked that it offered a reasonable trade off in terms of efficiency and accuracy (see pages 6 to 8). Furthermore, the use of Cook's D should also be considered in light of the other checks performed by SFG, such as the sampling exercise (discussed in Skeels, 2010a) which showed stability of the estimated parameter values. SFG also carefully examined standard errors and regression diagnostics during the course of the analysis.

Zero and negative drop-offs

McKenzie and Partington (2010c) have criticised the data in the SFG analysis for containing a number of zero and negative drop-off ratios. McKenzie and Partington stated that the number of zero drop-off observations in the SFG study is "higher than expected" (page 38). However, no benchmarks have been provided for comparison.

UED notes also that no evidence has been provided as to the number of zero and negative drop-offs in the Beggs and Skeels (2006) study. The AER has not tested this aspect of the study on which it relies and it is quite conceivable that the Beggs and Skeels (2006) results produce similar numbers of zero and negative drop-off ratios.

In relation to negative drop-offs, McKenzie and Partington (2010c) have argued that negative and zero drop-offs may bias the sample and should be removed (page 38). However, this recommendation overlooks an important consideration which is that the negative or zero-drop offs are caused by purely random events, and the exclusion of the contributing observations, without due consideration, could give rise to other biases in the sample. The omitted observations would contain potentially important information. As reported by SFG, in its response to the Victorian Draft Decision (SFG, 2010g):

> It would be wrong to routinely omit zero or negative drop-off observations. Such observations should only be omitted if they are erroneous, and there is no evidence of that.

Economically implausible results

In the Victorian Draft Decision, the AER has objected to one set of estimation results produced by SFG, claiming (on page 543) that:

> SFG's estimate of the value of theta in the 1 July 2000 to 10 May 2004 subsample period is not statistically different from zero. In addition to this, in the same period, SFG's estimate of the value of cash dividends is greater than one, which is economically implausible. The AER considers that this indicates the presence of multicollinearity in SFG's results.

The AER hasn't referenced a particular report, but is presumably drawing upon results in SFG (2009b) because SFG has not recorded results separately for the 2000 to 2004 period in its recent reports (SFG 2010a and 2010b). SFG has implemented a number of refinements to its approach since the publication of the February 2009 study (SFG, 2009b), and so the issues to which the AER refers may no longer be manifesting themselves in the estimation results.

Furthermore, Skeels (2010a) has presented a coherent argument that:

> If the point estimate is economically implausible but the confidence interval includes economically plausible values, as the preferred SFG results do, then the correct interpretation of the estimates is that they suggest that the true parameter is near to the boundary of economically plausible values. They do not suggest that the true parameter value is an economically implausible value. To attach an implausible interpretation to something when a plausible interpretation is equally probable does not constitute a fair assessment of the statistical evidence.

Skeels (2010a) also noted that the factors identified by the AER as possible reasons for the differences between the results of SFG (2009b) and Beggs and Skeels (2006), did not constitute sufficient reasons to dismiss the work of SFG (page 28 of Skeels, 2010a).

Consistency in AER parameter estimation

As noted in the SFG report in response to the Draft Decision (SFG, 2010g), the AER has also failed to address the two incompatible assumptions that it makes when deriving the return on capital:

- The AER's empirical estimates of theta (and consequently gamma) are conditional on an estimated value of cash dividends of 80 cents per dollar; and
- The AER's estimate of the required return on equity using the CAPM is conditional on cash dividends being valued at 100 cents per dollar.

There is a gross inconsistency in evidence here, and the AER has erred by using two different values for the same parameter when estimating the return on capital. In the GasNet decision, the Australian Competition Tribunal affirmed the importance of maintaining the mathematical integrity of the CAPM when estimating the WACC[88]. Accordingly, the AER must address the inconsistency issue and cannot maintain its previous approach in direct contravention of the principles established in the GasNet decision.

[88] Application by GasNet Australia (Operations) Pty. Ltd. [2003] ACompT 6.

9.10.3 Conclusions on gamma

UED proposes a gamma estimate of 0.2. A distribution rate of 0.69 has been taken from Hathaway (2010g2), and is an estimate derived from the latest taxation statistics. The appropriate estimate of theta is 0.2379, taken from SFG (2010a). The product of the two parameter values gives a gamma estimate of 0.164.

The calculation of gamma thus presented conforms to the definition in Monkhouse (1993).

UED submits that there are no sensible grounds for continuing to adopt a value of gamma of 0.65. The reasoning advanced by the AER in support of this value is deficient in a number of material respects:

- **A distribution rate which is completely at odds with empirical evidence**

The AER has ignored the weight of empirical evidence which demonstrates that the distribution rate is not 100 per cent, and is in fact likely to be around 70 per cent. The consultants engaged by AER have themselves acknowledged that the distribution rate is below 100 per cent.

Hathaway (2010g3) has adduced evidence which undermines the untenable position that the AER is seeking to maintain. In his expert report ("Practical Issues in the AER Draft Determination"), Hathaway (2010g3) states poignantly that:

> The assertion that the ultimate distribution of franking credits will be close to 100% over a five year period is incorrect. It flies in the face of all the evidence and all reason. The explanation of how companies are going to achieve this 100% payout is weak. Companies are struggling to maintain their historical payout ratios of just 70%. It has now dropped to 68% under the new tax system with the new rules for crediting the FAB. The suggested activities to achieve this 100% payout are already being practised and they are not delivering 70% payout, let alone 100% payout. If companies paid out the average of 68% for four years and then paid out all the retained credits at year 5, they would need to payout profits in year 5 at 228%. They must payout all retained profits over the last five years as an excessively large dividend in order to meet this 100% distribution of all credits. This is totally unrealistic. The retained profits will not be available for this payout and so the credits will not be 100% distributed.
>
> The related logic that "retained credits" have value is wrong. No matter what value one might put on these credits, it has to be multiplied by the probability of ever realising that value. For all practical reasons, that probability is zero. Unless the existing annual distribution of credits can be boosted to at least 100% per annum, the potential credits in the FAB will never be accessed and are effectively worthless.
>
> Calling the [Franking Account Balance] "retained credits" is misleading as it implies that they are readily available to be accessed. There is currently over $170 billion recorded in the FABs of all Australian companies. But that pool can only be accessed [in conjunction with] with franked dividends as the tax payment only becomes credits when so issued.

- **The Officer (1994) framework does not require a 100 per cent payout ratio**

The AER continues to assert that a 100 per cent distribution rate is consistent with the Officer WACC framework, even though this has been denied by Professor Officer himself (see Officer, 2009f). For his part, Hathaway (2010g3) has passed the following verdict:

> The assertion that the WACC models must assume 100% payout is wrong. I consider [that] the whole conceptual argument promulgated by the AER and its consultants is most misleading in asserting that just because Prof. Officer developed his models in a highly restrictive form that these models are condemned to only be used in that narrow form. I demonstrate that the two WACC formula of the Capital WACC (or vanilla WACC) and the Effective Classical WACC (the standard after tax WACC with the effective tax rate of $(1-\gamma)T$ in place of T) are both quite valid WACCs for scenarios that include growth, hence retained earnings are quite valid assumptions. Prof Officer's 1994 paper had an

extensive numerical example, called McKelly Corp. It has a classical and imputation valuation comparison. The example explicitly includes retained earnings for shareholders. It is not a 100% payout model. I think a number of practical issues have been distorted by misapprehensions of WACC models which has lead the AER to adopt what I consider are logically incorrect positions.

- **The tax study by Handley and Maheswaran (2008c) has been discredited, as a results of investigations undertaken by Hathaway, and reported in Hathaway (2010g1).** The AER should resile from using the flawed results of this published work. To-date, the AER has used Handley and Maheswaran (2008c) to derive an "upper bound" for theta, notwithstanding the deficiencies. The AER also appears to have misinterpreted the results of this study in deriving its "upper bound".

- **The SFG studies (2009b and 2010a) provide valid and defensible empirical estimates of theta.** The AER has relied on just one dividend drop-off study to estimate theta, notwithstanding the advice of its experts to take a more "balanced approach". The AER has cavilled at the more recent SFG (2009b and 2010a) studies, despite expert evidence to suggest that the results from this work are at least as reliable as the results from the Beggs and Skeels (2006) research paper.

- Furthermore, UED does not agree that an average of theta estimates from tax statistics and dividend drop-off studies - the method used by the AER - is appropriate in the circumstances.

9.11 UED's response to the Draft Decision on the estimated cost of corporate income tax

For the purpose of calculating the estimated cost of corporate income tax (the "tax wedge") UED's original Regulatory Proposal applied a tax rate of 30 per cent. This value is consistent with the company tax rate prescribed in the tax law.

As already noted, the Draft Decision applied a reduced company tax rate of 29 per cent from 2013-14 and 28 per cent from 2014-15. These rates are consistent with the Government's response to the Henry Review. Although the Government had announced tax reforms and had set out these proposed changes to the tax rates, it is notable that soon after the AER published its Draft Decision, the Government announced changes to the proposed super profits tax on mining which have a consequential effect on the proposed company tax changes. The Government has now confirmed that any proposed changes to the company tax regime will not be presented for consideration in parliament until after the next general election (expected later this year).

The AER's decision to include tax rates that reflect Government proposals that have since been amended is inconsistent with the AER's treatment of possible legislative or regulatory change in other areas of the Draft Decision. For instance, the AER has provided additional expenditure allowances only for those items where a clear, legislated change exists:

- The expenditure implications arising from the Victorian Bushfire Royal Commission have not been included in the Draft Decision.

- Similarly, changes to safety legislation that take effect on 30 June 2010 have not been dealt with by the AER.

The AER's approach in these instances is in contrast to its adoption of the former Rudd Government's proposed changes in company tax rates from July 2013.

The AER will be aware that the Rules contain a provision to deal with tax change events. Chapter 10 of the Rules defines a tax change event as follows:

> A tax change event occurs if:
>
> (a) any of the following occurs during the course of a regulatory control period for a Transmission Network Service Provider or a Distribution Network Service Provider:
>
> (i) a change in a relevant tax, in the application or official interpretation of a relevant tax, in the rate of a relevant tax, or in the way a relevant tax is calculated;
>
> (ii) the removal of a relevant tax;
>
> (iii) the imposition of a relevant tax; and
>
> (b) in consequence, the costs to the service provider of providing prescribed transmission services or direct control services are materially increased or decreased.

A change in the company tax rate falls under the definition of a tax change event. The AER should rely on the correct application of the Rules in its Final Decision and for the purpose of determining the estimated cost of corporate income tax, it should apply the legislated tax rates in force today. In the event that a change in the corporate tax rate occurs over the course of the regulatory period (noting that this is by no means certain) the change in costs can be managed under the cost pass through arrangements.

9.12 Forecast inflation

UED proposes an inflation forecast of 2.57 per cent, which has been derived using the method put forward by the AER in its draft decision.

The UED assessment of forecast inflation, shown in Table 9-5, is consistent with that in the AER's draft decision. The overall inflation forecast is calculated as the geometric average of the projected annual inflation rate for each of the ten years from 2011 to 2020.

Table 9-5: Forecast inflation (per cent per annum)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inflation Forecast	2.75%	3.00%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Geometric Average										**2.57%**

Note: Inflation forecasts are for the year to June. Reserve Bank of Australia, Statement on Monetary Policy, 06th May 2010, page 56, Table 14.

UED's explanation of the ten individual annual inflation forecasts shown above is as follows:

- For the first two years, the forecasts are the expected inflation outcomes stated in the Reserve Bank of Australia's most recent Statement on Monetary Policy.
- For the subsequent eight years, the forecasts are based on the mid-point of the RBA's long term inflation target range. The forecast range is 2 to 3 per cent, and so the mid-point is 2.50 per cent.

9.13 UED's revised WACC and estimated cost of corporate tax

UED has calculated a nominal vanilla WACC for its Revised Regulatory Proposal of 10.29 per cent. The cost of capital has been worked out using the formulae in the PTRM prepared by the AER, however UED has applied its own input data.

The values of the parameters underpinning the WACC are shown in Table 9-6 below. The table also provides references to the relevant sections of this chapter in which evidence is presented to substantiate the proposed parameter values.

Table 9-6: Updated assessment of the nominal WACC for UED

Parameter	Value for Revised Regulatory Proposal	Section Reference to Revised Regulatory Proposal
Nominal risk free rate	5.65%	Section 9.3
Equity beta	0.8	Section 9.4
Market risk premium	6.5%	Section 9.6
Gearing (D/V)	60%	Section 9.7
Debt margin (excluding debt raising costs)	4.28%	Section 9.8
Utilisation of imputation credits (γ)	0.20	Section 9.9
Cost of equity (K_e)	10.85%	Derived series
(Pre-tax) Cost of debt (K_d)	9.93%	Derived series
Nominal vanilla WACC	**10.29%**	**Derived series**
Real vanilla WACC	**7.53%**	**Derived series**

Source: United Energy Post-Tax Revenue Model. The model provided by the AER for the Draft Decision has been updated with new parameter values. The nominal risk free rate has been worked out as an average over the reference period, which covers 30 business days from 19th April to 31st May 2010.

UED is proposing to depart from the value for gamma set out in the SORI (AER, 2009e3). The discussion of gamma is in section 9.9. A different method has also been proposed for calculating the debt risk premium, and the arguments have been presented in section 9.8. UED has accepted the market risk premium of 6.5 per cent, which is reported in the SORI, but has presented cogent arguments and compelling evidence in section 9.6 as to why a higher value of the MRP can be supported.

This chapter has briefly considered the equity beta, the gearing ratio, and the expected inflation rate. UED intends to accept the Draft Decision values for the equity beta and the level of gearing. In addition, UED does not oppose the method for forecasting inflation which the AER has put forward in section 11.5.6 of the Draft Decision. UED understands that the AER will update its projections of inflation for the forthcoming regulatory period once the Reserve Bank of Australia has released an inflation forecast for the year ending December 2013. The predicted inflation rate is an input into the calculation of the real vanilla WACC.

The Draft Decision values for the equity beta and gearing are consistent with those specified in the SORI. The equity beta and gearing are discussed in sections 11.5.4 and 11.5.1 of the Draft Decision, respectively.

10. Other Building Block Elements

Key messages

UED's original Regulatory Proposal explained that:

- In the current regulatory period, UED has been subject to an S-factor and Efficiency Carryover Mechanism (ECM) in accordance with the ESCV's determination.
- The AER has established a Service Target Performance Incentive Scheme and Efficiency Benefit Sharing Scheme in accordance with the Rules requirements. These schemes effectively replace the S-factor and ECM.
- The AER's framework and approach paper recognises that it is appropriate to give effect to the ESCV's S-factor and ECM schemes by including appropriate amounts in the building block calculation for the forthcoming regulatory period.

The AER's Draft Decision argued that:

- The ESCV S-factor scheme should be closed out, and service performance for 2009 and 2010 should be subject to a penalty or a reward.
- The ESCV scheme will continue to apply in 2011 and in 2012, although the calculated penalties or rewards will not be used to adjust tariffs directly, but will instead enter the building block. Furthermore, carry forward amounts calculated under the scheme will continue to have an impact until 2018.
- The AER's model calculates the aggregate penalty to be paid by UED over the period from 2011 to 2018 as $101.6 million (measured in $2010). This value is comprised of the undiscounted sum of S-factor building block components from 2011 to 2015. In addition, the value of penalties, resulting from t-6 components, in 2016, 2017 and 2018 has been discounted back to 2015.

In this Revised Regulatory Proposal, UED explains that:

- The ESCV's S-factor scheme was not designed to be closed out. UED previously pointed out to the ESCV that its scheme may deliver unanticipated outcomes. The AER's Draft Decision illustrates UED's point.
- The AER's S-factor close out mechanism imposes a penalty on UED of approximately $102 million, which is a massive and unexpected penalty especially as UED's network performance has never been criticised by the AER.
- UED's original Regulatory Proposal used the same data, but an alternative mathematical formulation for the close out. An equally valid formulation derived a penalty of approximately $2 million upon cessation of the S-factor scheme. The $100 million difference between calculations undertaken by UED and the AER, based on alternative mathematical formulations, proves that a mathematical close out mechanism, where none was predetermined, is problematic. The incentives on distributors vary widely between the alternative formulations and incentives are considered are to be severely distorted under the AER's mechanism.
- UED's view is that a mathematical solution to closing out the S-factor scheme should

no longer be pursued. Instead, the S-factor scheme should simply stop and no carryover amount should be included in the building blocks. This is consistent with the National Electricity Objective and the National Electricity Law.

10.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal proposed for the forthcoming regulatory period:

- tariff adjustments arising from the operation of the S-factor (service improvement incentive) scheme put in place by the ESCV in its Final Determination for the 2006-2010 electricity distribution price review; and
- revenue increments arising from the operation of the ESCV's efficiency carry-over mechanism (ECM) scheme that applies in relation to and operating cost efficiencies.

The original Regulatory Proposal noted that the AER has recognised the importance of honouring these two incentive schemes. It also noted comments made by the AER in its Framework and Approach Paper[89] and in the RIN[90], in respect of the S-factor and ECM schemes.

10.1.1 S-Factor

In relation to the S-Factor, UED's original Regulatory Proposal explained UED's view that:

1. UED's service performance for years 2009 and 2010 should be subject to the S-factor scheme.
2. The financial impact of the term $\left(1+S_{t-6}^{'}\right)$ would extend beyond the current regulatory period.

UED proposed a methodology for giving effect to the ESC's S-factor scheme, noting that the scheme contemplated that it would continue beyond the current regulatory period. The ESC therefore did not describe the calculation that should apply if the scheme were brought to a close.

10.1.2 Efficiency carryover mechanism

UED's original Regulatory Proposal applied the calculation methodology specified in the ESCV's 2001-05 Final Decision to determine the efficiency carry over amounts to be added to the company's revenue in the forthcoming regulatory period, in respect of efficiency gains made in the current period. The amounts proposed are shown below in Table 10-1.

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89 Australian Energy Regulator, Framework and Approach Paper for Victorian Electricity Distribution Regulation. Citipower, Powercor, Jemena, SP Ausnet and United Energy. Regulatory control period commencing 1 January 2011. Australian Energy Regulator. Final, May 2009. Pages 96 and 112.

90 Clauses 10.1(a)(iv) and (v), and 10.2 of the RIN.

Table 10-1: Proposed carry-over values for next regulatory period

Cary-over amounts years:	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Carry-over amounts from years:					
2006	3.2	-	-	-	-
2007	7.6	7.6	-	-	-
2008	- 0.2	- 0.2	- 0.2	-	-
2009	-1.4	-1.4	-1.4	-1.4	-
2010	-	-	-	-	-
Sum of efficiency carry-over	9.2	6.0	-1.6	-1.4	-

Source: UED calculations and financial model for EDPR 2011 to 2015. Methods outlined in section 4.2, ESCV (2004a) and chapter 10, ESCV (2005a). Amounts shown are in real 2010 terms.

10.2 AER's Draft Decision on the S-Factor

10.3 Imposition of an unexpected and unreasonable penalty

The AER's Draft Decision sets out a method for closing out the ESCV S-factor scheme. The choice of method was not discussed with UED prior to the release of the Draft Decision. The Draft Decision imposed a cumulative penalty on UED of $102 million, which is an unprecedented penalty for service performance. The level of the penalty is particularly staggering given that the AER has not criticised or warned UED in relation to its service performance. The AER's $102 million penalty contrasts sharply with the $2 million penalty calculated by UED, using exactly the same performance data.

It is self evident that arrangements for closing out the ESCV's S-factor scheme are dysfunctional both in terms of the massive range in possible outcomes using the same performance data, and in terms of the AER's consultation process. It is untenable that one of the largest financial penalties for non-performance in Australian corporate history could be imposed by the AER without any dialogue with the company concerned.

UED contends that the unexpected and unreasonably large magnitude of the penalty from the AER's close out mechanism should have alerted the AER to serious problems with its approach. The fundamental problem with the AER's close out arrangement is that any attempt to mathematically close out the scheme undermines the basic design principles and incentive properties.

As a consequence of the S-factor design, any attempts to close out the scheme will deliver spurious and unintended outcomes such as those calculated by the AER in its Draft Decision. UED has previously highlighted a number of peculiar features inherent in the ESCV's S-factor scheme, which have the potential to create unintended and illogical outcomes. In a submission to the ESCV in August 2005, UED explained its concerns regarding the design of the S-factor scheme and highlighted it would only provide appropriate bonus and penalties if certain onerous conditions were met[91]:

> "In fact, through a detailed examination of the original design of the S-factor scheme (summarised here but set out in full in Appendix 1 of this submission) UED has identified an important and fundamental error in the Commission's approach.
>
> Despite the rather peculiar timing of bonus and penalty payments under the Commission's scheme, UED considers that it does actually create appropriate performance incentives, providing that the following conditions are met:
>
> a. The Commission commits to "flat" target rates for all future regulatory periods;
>
> b. The Commission commits not to revisit the agreed targets, even if actual performance systematically deviates from the target rates; and
>
> c. UED accepts that the Commission will honour its commitments in relation to (a) and (b).
>
> These conditions appear to be onerous and unrealistic (and perhaps they are) but - as Appendix 1 demonstrates - without them the Commission's proposed scheme will not work as intended. For it is only the potential for a company to receive annual rewards in perpetuity that give rise to the need for a lagged penalty to curtail these rewards after 6 years. This potential only arises when the above conditions are met."

It is self evident that the conditions described by UED for the proper working of the S-factor scheme cannot hold if the scheme closed out. It follows, therefore, that any attempt to close out the scheme is likely to deliver a spurious or illogical outcome because the proper functioning of the S-factor scheme depends on its continued operation.

10.4 No correct formulation of the close out can be developed

It follows from the above discussion that there is no objectively correct mechanism for closing out the ESCV's S-factor scheme. As a result, any close out arrangement chosen will be arbitrary and the resulting penalty or bonus payments will also be arbitrary or random depending on the close out method selected. A random or arbitrary outcome violates the original design principles of the S-factor scheme as described by the Office of the Regulator-General in its Draft Determination for the 2001 Electricity Distribution Price Review:

(a) the incentives should be specified clearly and in advance, to maximise their effectiveness;

(b) the scheme should be as simple as possible to understand for both distributors and customers, without distorting the incentives;

(c) the incentives should be based on reliable and verifiable performance measures, with independent scrutiny of the distributors' measurement of their performance;

(d) the incentives should address worst-case performance as well as average performance, to ensure that benefits flow to all customers;

91 UED, Submission to the Essential Services Commission, S Factor, August 2005, page 13.

(e) the incentives should encompass both penalties for under-performance and rewards for superior performance;

(f) the amount of revenue that distributors stand to gain or lose under the incentives should be limited, but large enough to provide meaningful commercial incentives at the margin. The amount of the incentives should be greater than the cost to distributors of achieving an increment of reliability, but less than the value that customers place on that increment of reliability;

(g) there should be no exclusions for external events, such as severe storms or load shedding due to a shortfall in generation capacity. Such risks are better allocated to distributors than customers, given that distributors have a greater capacity to mitigate their impact;

(h) where incentive payments are to be paid directly to specific customers for specific events, the scheme should provide for automatic payments rather than payment on application by the customer; and

(i) customers should retain any right they currently have to seek additional compensation for specific losses caused by supply interruptions.

With the exception of principle (g), which the Office later determined to be inappropriate, the subsequent 2001 Electricity Distribution Price Determination attempted to embody these principles in the design of the S-factor scheme and to codify them in algebraic terms. The AER's proposed close out mechanism violates principles (a), (b) and (f) as follows:

- The incentives have not been specified clearly and in advance, to maximise their effectiveness. In fact, the AER's close out arrangement retrospectively imposes a higher incentive rate in relation to 2010 performance.
- The scheme is not as simple as possible, and cannot be understood by distributors and customers. In fact, the calculation of the close out arrangement is so complex that the AER is evidently unaware of the distorted incentives that it introduces.
- The amount of revenue that distributors stand to gain or lose as a result of performance in 2010 is not consistent with appropriate incentives.

It is also noted that the AER's close out mechanism has the effect of continuing the operation of the ESCV's scheme to 2016, even though a new service incentive scheme, the STPIS, is to be introduced at the commencement of the forthcoming regulatory period. An appropriate close out arrangement would prevent the ESCV's scheme from continuing into the forthcoming regulatory period. The operation of two schemes in parallel is also inconsistent with principles (a), (b) and (f).

Importantly, the violation of these principles means that the AER's proposed close out mechanism also violates the National Electricity Objective, which is set out below:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity".

Efficient investment to improve network reliability cannot be achieved if random or arbitrary penalties are imposed unexpectedly on a business. UED notes that legislative guidance is provided to the AER in section 16 of the National Electricity Law, which states that:

> *(1) The AER must, in performing or exercising an AER economic regulatory function or power—*
>
> > *(a) perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national electricity objective.*

The National Electricity Law defines an 'AER economic regulatory function or power' as:

> *a function or power performed or exercised by the AER under this Law or the Rules that relates to:*
>
> > *(c) the making of a transmission determination or distribution determination*

In addition, section 16 (2) states that:

> *In addition, the AER—*
>
> > *(a) must take into account the revenue and pricing principles—,*
> >
> > > *(i) when exercising a discretion in making those parts of a distribution determination or transmission determination relating to direct control network services.*

In light of these provisions in the National Electricity Law, UED's view is that the AER should not close out of the ESCV's S-factor scheme. Instead, the ESCV's scheme should simply cease to have any effect at the end of the current regulatory period, being 31 December 2010.

10.4.1 UED's conclusions regarding the S-factor close out arrangements

The nature of the ESCV's S-factor scheme means that any close out mechanism will contain arbitrary assumptions that cause random penalty or bonus payments that cannot be justified by reference to the original design features of the S-factor scheme. UED therefore does not favour a mathematical solution to the close out mechanism. UED's view is that the scheme should simply not proceed from 31 December 2010 and that no close out amount should be included in the building blocks for the forthcoming regulatory period.

UED also notes that the AER's proposed close out mechanism is inconsistent with the National Electricity Objective. The National Electricity Law and Rules provide support for stopping the ESCV's S-factor scheme as proposed by UED.

UED previously said that the appropriate way to close out the ESCV's S-factor scheme is through the price control formula applicable to tariffs for 2011 and 2012[92]. UED's submission is now that there should be no close out consequences beyond 2010. As noted earlier, in the Framework and Approach Paper the AER said that adjustments for the S-factor would be addressed through the revenue building blocks[93] rather than tariffs and the

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92 UED, Regulatory Proposal, November 2009, page 162.

93 AER, Framework and Approach Paper for Victorian Electricity Distribution Regulation. Citipower, Powercor, Jemena, SP Ausnet and United Energy. Regulatory control period commencing 1 January 2011. Australian Energy Regulator. Final, May 2009, page 75

AER has continued to take that view in the Draft Decision[94]. UED reiterates that the AER's approach is impermissible and that the price formula would have been the appropriate mechanism to deal with the matter. The ESCV's S-factor scheme operating during the period 2006 to 2010 does not give rise to revenue increments or decrements for the inclusion in the building blocks in the next regulatory period.

10.4.2 Reliability performance for calendar year 2010

The information below provides an updated estimate of UED's 2010 performance.

In its regulatory proposal, UED provided annual reliability performance figures for unplanned SAIDI, unplanned SAIFI, and momentary MAIFI. Actual results were shown for calendar years 2005 to 2008, while an estimate of performance was provided for 2009 based on nine months of actual data. A forecast of reliability performance was also developed for 2010. The 2010 forecast was underpinned by a working assumption that performance would revert to an average level by 2013.

The procedure which was followed to predict performance levels in 2010 was documented in simple steps which are explained below:

i. An arithmetic average of the performance results from 2005 to 2009 was worked out. The unplanned SAIDI, SAIFI and MAIFI indices were then assumed to be equal to these average values in 2013.

ii. A compound growth rate was calculated for the change in performance from 2009 to 2013.

iii. The calculated compound growth rate was applied to the performance results for 2009, thus deriving estimates for 2010.

In essence, reliability performance was predicted to improve geometrically from 2009 through to 2013.

The approach described above was not used for call centre performance numbers because the call centre series has exhibited less volatility over the few years in which it has been applied. The call centre results for 2010 were calculated as an average of the calendar year performance levels from 2005 to 2009.

The estimated reliability of service performance and customer service performance figures for 2010 are shown below. These numbers were current as at March 2010.

Table 10-2: Actual outcomes to 2009, estimated performance for 2010 (as at March 2010)

URBAN	Units	2005	2006	2007	2008	2009	2010
Unplanned (SAIFI)	Index	0.822	0.882	0.963	0.924	1.199	1.133

94 AER, Draft Decision, page 680.

URBAN	Units	2005	2006	2007	2008	2009	2010
Momentary (MAIFI)	Index	1.318	1.120	1.012	0.955	1.121	1.117
Unplanned SAIDI	Minutes off-supply	49.735	58.281	57.526	61.530	95.788	86.795
RURAL							
Unplanned (SAIFI)	Index	1.677	1.571	1.395	1.564	2.903	2.584
Momentary (MAIFI)	Index	2.823	1.527	1.650	2.111	2.744	2.588
Unplanned SAIDI	Minutes off-supply	79.738	72.341	89.486	85.069	201.251	171.276
ENTIRE REGION							
Unplanned (SAIFI)	Index	0.950	0.992	1.031	1.026	1.469	1.364
Momentary (MAIFI)	Index	1.544	1.184	1.113	1.138	1.378	1.350
Unplanned SAIDI	Minutes off-supply	54.252	60.520	62.599	65.266	112.529	100.205
ENTIRE REGION							
Call centre performance	%	73.79%	72.86%	74.01%	73.03%	73.15%	73.38%

Source: Tariff approval submissions to the ESCV until 2009. Estimated performance figures for 2010. The numbers in this table differ from those presented in the context of the STPIS discussion owing to the application of different criteria for the treatment of excluded days. The ESCV exclusion regime is based on SAIFI, with the threshold for an excluded day being 0.100. The definition of call centre performance under the ESCV S-factor scheme also differs from that which will be applied under the AER scheme.

The method of projecting reliability of supply performance was essentially developed for analytical convenience. There was never any certainty that the forecasts would be a realistic representation of out-turn performance for 2010. To date, the improvement in reliability of supply performance from 2009 to 2010 has been more pronounced than expected. Unplanned minutes off-supply, unplanned interruptions, and momentary interruptions have been significantly lower over the first six months of 2010 than over the equivalent period in 2009. The results are shown below for purposes of comparison.

Table 10-3: Year-to-date performance outcomes, 2009 and 2010

ENTIRE NETWORK 2010	Jan	Feb	Mar	Apr	May	Jun	YTD
Unplanned (SAIFI)	0.113	0.139	0.059	0.045	0.073	0.004	0.472
Momentary (MAIFI)	0.084	0.068	0.057	0.063	0.074	0.03	0.03
Unplanned SAIDI	7.43	7.61	3.27	3.23	3.42	3.06	28.02
ENTIRE NETWORK 2009	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**YTD**
Unplanned (SAIFI)	0.419	0.164	0.126	0.162	0.080	0.042	0.993
Momentary (MAIFI)	0.090	0.094	0.113	0.080	0.051	0.028	0.457
Unplanned SAIDI	47.72	15.18	10.83	11.17	3.60	3.06	91.56

Source: Monthly network performance figures submitted to the AER. The figures are shown gross; major event days have not been taken into consideration. Momentary MAIFI is shown in respect of feeder outages only.

UED has also prepared revised estimates of reliability performance for calendar year 2010, drawing upon actual outcomes for the first six months of the year, and historic data on network performance from July to December for calendar years from 2005 to 2009, inclusive. This is shown in the table below.

Table 10-4: Forecast of reliability performance for calendar year 2010

2010	Actual results	Average, 2005 to 2009	Forecast
	January to June	July to December period	Full year, 2010
URBAN			
Unplanned (SAIFI)	0.506	0.412	0.918
Momentary (MAIFI)	0.469	0.502	0.971
Unplanned SAIDI	29.966	22.229	52.196
RURAL			
Unplanned (SAIFI)	0.780	0.718	1.498
Momentary (MAIFI)	1.268	0.874	2.142
Unplanned SAIDI	52.805	44.581	97.386

At this stage, the final outcome for 2010 performance remains uncertain. However, UED has recalculated the likely S-factor close out if the AER's mechanism were adopted in the Final Decision. UED's estimates show that the most likely outcome is a payout by UED of $11.6 million in NPV terms, expressed in 2010 prices. Alternatively, on a 'best case' scenario, UED could receive a benefit of $14 million. This significant variation in the likely payout has led UED to examine carefully the AER's method for closing out the scheme.

10.4.3 Discussion of the AER's proposed S-factor payout

The AER proposes to calculate the payout by using a spreadsheet that simulates the continuation of the ESC S-factor mechanism through to 2018. The simulation spreadsheet calculates the dollar amount of reward or penalty that the ESCV mechanism would have applied to a DB if it had continued

S-factor rewards and penalties in the ESCV mechanism are driven by DB performance. Without knowledge of – or assumptions on – performance, it is impossible to calculate the corresponding rewards. The ESCV scheme through to 2010 was driven by actual DB performance through to 2008. Similarly, for the AER to simulate continuation of the scheme through to 2018, it is necessary for it to simulate DB performance through to 2016. The ESCV algebra requires DB performance as its key input.

In its approach, the AER has defined S''t to be zero for 2013 through to 2018. In the ESCV algebra, S''t=0 if and only if performance in year t-2 is equal to performance in year t-3. Thus, by defining S''2013=0, the AER is defining simulated performance in 2011 to be equal to 2010 performance. Similarly, by defining S''2014=0, the AER is defining simulated 2012 performance to be equal to 2011 performance, which equals 2010 performance, and so on. In summary, for the purposes of simulating S-factor payments, the AER has implicity assumed that DB performance in 2011 to 2016 to be a continuation of actual performance in 2010.

The AER has not acknowledged that it has made this assumption on future DB performance and thus has not attempted to justify it. However, this assumption introduces two particular problems with the AER's proposed close out of the ESCV's scheme:

- Double jeopardy. The AER's close out mechanism has the effect of continuing the ESCV's scheme to 2016, even though a new service incentive scheme, the STPIS, is to be introduced at the commencement of the forthcoming regulatory period. A proper close out arrangement would prevent the ESCV's scheme from continuing into the forthcoming regulatory period.
- A multiplier effect. The AER's close out mechanism inadvertently subjects performance in 2010 to a multiplier effect as the performance in 2010 is implicitly assumed to continue to 2016.

It is the multiplier effect that causes the payouts from the AER's close out mechanism to vary so significantly depending on 2010 performance.

10.4.4 UED's conclusions regarding the S-factor close out arrangements

UED's latest forecast for 2010 performance is substantially improved from the estimate presented in UED's original Regulatory Proposal. As a result, the application of the AER's close out mechanism is most likely to require a payout by UED of $11.6 million in NPV terms, expressed in 2010 prices. Alternatively, on a 'best case' scenario, UED could receive a benefit of $14 million. There is a substantial risk for UED and customers if 2010 actual performance is significantly better or worse than suggested by UED's latest estimates.

These significant variations in the likely payout has led UED to examine carefully the AER's method for closing out the scheme. Our examination of the technical aspects of the AER's approach reveal that there are serious problems with the AER's formulation. In particular, it exaggerates the impact of 2010 performance by implicitly assuming that this performance continues to 2016.

UED has consistently said that the appropriate way to close out the ESCV's S-factor scheme is through the price control formula applicable to tariffs for 2011 and 2012[95]. As noted earlier, in the Framework and Approach Paper the AER said that adjustments for the S-factor instead would be addressed through the revenue building blocks[96] and has continued to take that view in the Draft Decision[97]. UED continues to believe that the AER's approach is impermissible and that the price formula is the appropriate mechanism to deal with the matter.

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95 UED, Regulatory Proposal, November 2009, page 162.

96 AER, Framework and Approach Paper for Victorian Electricity Distribution Regulation. Citipower, Powercor, Jemena, SP Ausnet and United Energy. Regulatory control period commencing 1 January 2011. Australian Energy Regulator. Final, May 2009, page 75

97 AER, Draft Decision, page 680.

10.5 AER's Draft Decision on the ECM

Pages 560 to 562 of the Draft Decision explain the AER's reasoning as follows:

- United Energy proposed an efficiency carryover amount of $12 million ($2010) to be included in its building block revenue requirement. This amount was calculated by comparing the benchmark allowance and the actual expenditure inclusive of related party margins.

- The ESCV determined United Energy's benchmark allowance exclusive of related party margins by establishing United Energy's benchmark allowance based on its actual costs prior to any related party contractual arrangements that were in place. Accordingly, the AER considers that United Energy's carryover amounts should be determined in a similar way by comparing the benchmark allowance exclusive of margins (that is, based on the actual incurred costs of the related party and not the contract charges).

- The AER notes that if United Energy's carryover amount is determined exclusive of related party margins, the carryover amount is reduced to negative $50 million.

- This negative carryover amount arises because it is based on the actual costs of United Energy's related party service provider (which includes the loss in providing operating services to United Energy). However, the application of a carryover amount for United Energy excluding related party margins would result in an anomalous outcome. That is, United Energy has been receiving an efficiency gain in the form of a lower cost within the current regulatory control period as its related party provider has supplied services at a loss. However, if the carryover amount is determined excluding related party margins, this efficiency gain would register as an efficiency loss for any carryover amounts included in the forthcoming regulatory control period.

- The AER has decided to use its discretion to not apply the negative carryover amounts associated with efficiencies arising from the current regulatory control period to United Energy.

10.6 UED's response to the AER's Draft Decision on the ECM

UED accepts the AER's decision to apply its discretion to not apply any negative carryover amount associated with efficiencies arising from the current regulatory control period to UED. Notwithstanding UED's acceptance of the AER's Draft Decision, UED does not necessarily accept that the proper application of the ECM would result in a negative carryover amount. UED considers that as an efficient distribution network service provider it would be anomalous for UED to be penalised for its cost performance in the current regulatory period. UED also notes that the Revenue and Pricing Principles in the National Electricity Law support the AER's exercise of its discretion to set any negative carryover amount to zero. For the purposes of this Revised Regulatory Proposal, therefore, UED accepts a carryover amount of zero.

11. Total revenue and X factor

Key messages

UED's original Regulatory Proposal explained that:

- The proposed price increase for 2011 is 16.6 per cent.
- X for 2012 – 2015 is set at 4.0 per cent so that the final year of revenue aligns as closely as possible to the forecast building block cost.
- UED's calculation of the X factor accords with the requirements of clause 6.5.9 of the Rules.

The AER's Draft Decision determined that:

- UED's X factor for 2011 is 19.57 per cent.
- The X factors for the years 2012 to 2015 inclusive are: zero, 2 per cent, 3 per cent and 5 per cent.

In this Revised Regulatory Proposal, UED explains that:

- The proposed price increase for 2011 is 16,83 per cent
- X for 2012 – 2015 is set at 4.0 per cent so that the final year of revenue aligns as closely as possible to the forecast building block cost.
- UED's calculation of the X factor accords with the requirements of clause 6.5.9 of the Rules.

11.1 Recap on UED's Regulatory Proposal

Chapter 11 of UED's original Regulatory Proposal presented a summary of the company's building block proposal, its proposed X factor and its indicative prices for direct control services.

Table 11-1 below provides a summary of the composition of the unsmoothed building block revenue requirement proposed by UED.

Table 11-1: Proposed total revenue requirements

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Return on Capital	115.7	124.1	131.1	137.2	141.6
Depreciation	84.0	89.7	96.6	100.7	105.2
Non-capital costs	123.8	120.2	119.7	119.2	118.9

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Efficiency carry-over	9.2	6.0	-1.6	-1.4	0.0
Estimated cost of corporate income tax	6.2	7.3	8.6	11.0	12.4
Total Revenue	**339.0**	**347.4**	**354.4**	**366.6**	**378.0**

Amounts shown in real 2010 terms.

UED's original Regulatory Proposal explained that an X factor of 4.0 per cent had been proposed as this ensures that the forecast tariff revenues and building blocks costs will be closely aligned in 2015 and provides a relatively stable price path from 2012 - 2015. This proposal is consistent with the approach previously adopted by UED and is consistent with the Rules. The proposed X factors are shown in the table below.

Table 11-2: Proposed Annual X Factors

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Annual X Factor	-16.83%	-4.0%	-4.0%	-4.0%	-4.0%

UED's original Regulatory Proposal provided an analysis of typical customer/pricing outcomes under the X factors proposed by the company, noting that the proposal relates to the distribution component only. A summary of a typical residential bill was provided in Table 11-3 as follows:

Table 11-3: Analysis of 'typical' residential bill under UED's original Regulatory Proposal

	Current invoice (2010)	New invoice (2011)	% Change
Generation	$200	$200	0.0%
Transportation	$100	$100	0.0%
Distribution	$290	$338	16.8%
Retail	$360	$360	0.0%
AIMRO	$70	$70	0.0%
Total Invoice	**$1,020**	**$1,068**	**4.7%**

Amounts shown in real 2010 terms.

Note that the effect of and distribution price changes will be subject to the local retailer passing on any price changes. The table is for illustrative purposes only.

11.2 AER's Draft Decision on total revenue and X Factors

Table 11-4 (Table 18.29 on page 771 of the Draft Decision) sets out the AER's conclusion on UED's revenue requirements and X factors as follows:

Table 11-4: AER conclusion on United Energy's revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		134.3	142.2	149.4	155.6	161.8
Regulatory depreciation		36.0	42.7	50.2	57.9	66.2
Operating expenditure		92.9	95.8	99.7	105.6	108.9
Efficiency carryover amounts		0.00	0.00	0.00	0.00	0.00
S factor amounts		-5.1	-19.8	-19.2	-20.1	-47.6
Tax allowance		4.8	5.6	6.7	7.2	7.8
Annual revenue requirements		262.9	266.6	286.8	306.2	297.0
Expected revenues	296.2	249.5	262.1	281.0	303.5	332.2
Forecast CPI (%)		2.57	2.57	2.57	2.57	2.57
X factors		19.57	0.00	-2.00	-3.00	-5.00

Note: Positive values for X indicate real price decreases under the CPI – X formula.
Source: PTRM

11.3 UED's response to the AER's Draft Decision on total revenue and X Factors

For the reasons provided elsewhere in this revised regulatory proposal UED does not agree with the AER 's revenue requirements or x factors. Based on the information contained in this revised regulatory proposal the building block costs are provided in the table below:

Table 11-5: Revised revenue requirements

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Return on Capital	104.5	113.7	122.0	128.6	131.7
Depreciation	75.2	85.2	97.1	107.2	113.9
Non-capital costs	131.9	128.3	126.3	125.7	125.3
Efficiency carry-over	0.0	0.0	0.0	0.0	0.0
Estimated cost of corporate income tax	10.7	12.2	15.0	19.0	22.6
Total Revenue	**322.3**	**339.3**	**360.4**	**380.4**	**393.4**

Based on these revenue requirements the revised x factors to apply in the forthcoming regulatory period are provided in the table below:

Table 11-6: Revised X factors

	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Annual X Factor	-16.83%	-4.0%	-4.0%	-4.0%	-4.0%

12. Service Classification

Key messages

UED's original Regulatory Proposal explained that:

- UED has adopted the same service classification as that proposed by the AER in its Framework and Approach Paper with the exception of connection and augmentation works for new customer connections, which the AER proposed to be classified as negotiated distribution services.
- UED is concerned that the proposed service classification of connection and augmentation works for new customer connections is inconsistent with current regulatory arrangements.
- UED is concerned that the proposed service classification of connection and augmentation works for new customer connections will result in the expenditure incurred in good faith in the current regulatory period being stranded, contrary to the national electricity objective and the revenue and pricing principles.
- UED is concerned that the AER's proposed classification of connection and augmentation works for new customer connections will result in an upfront 100 per cent contribution for customers in order to minimise the risk of asset stranding. Such an outcome would be contrary to customers' interests and inconsistent with the national electricity objective and the revenue and pricing principles.
- The service classifications proposed by UED address these concerns, and accord with the requirements of the Rules.

The AER's Draft Decision accepted UED's classification of new connections requiring augmentation works as standard control services.

UED welcomes the AER's acceptance of the classification of new connections requiring augmentation works as standard control services. This revised proposal gives effect to the AER's draft decision in this matter.

12.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal noted that the AER's Framework and Approach Paper concluded that its standard and non-standard connection and augmentation works would be classified as negotiated distribution services because:

- the market for these services is contestable and characterised by several participants in the market;
- the AER has assumed that the regulatory obligations applicable to DNSPs for the tendering of construction works (currently under the ESC Guideline No. 14 and the DNSPs' licences) will continue in some form after 2010; and

- there is no economic need for direct control regulation.

The original Regulatory Proposal noted that whilst the framework paper is not binding on the AER or UED, clause 6.12.3(b) of the Rules provide that the classification of services in a distribution determination must be as set out in the framework paper unless the AER considers that, in light of UED's original Regulatory Proposal and the submissions received, there are good reasons for departing from the classification proposed in the framework paper.

UED proposed to adopt the same service classification as that proposed by the AER in its Framework and Approach Paper with the exception of connection and augmentation works for new customer connections, which the AER proposed to be classified as negotiated distribution services.

UED submitted that there are good reasons for departing from the classification proposed in the AER's Framework and Approach Paper in respect of connection and augmentation works for new customer connections because the AER's likely approach is inconsistent with the regulatory framework and departs from a relevant previous approach. In particular, UED submitted that the AER's proposed (different) classification is not more appropriate than the present classification because:

- it does not properly apply the regulatory framework;
- it does not have regard to the regulatory approach previously applicable to the relevant service;
- it does not have regard to the virtues of the previous classification under the previous regulatory system; and
- it risks stranding current period expenditure incurred in good faith.

UED therefore proposed that:

- new connection and augmentation works be properly characterised as assets that form part of the distribution system that provides standard control services and that there is no separate service capable of classification; or
- alternatively, that the service be classified as a standard control service.

In either case, as a pricing matter, the original Regulatory Proposal noted that the costs of those works will be recovered through UED's total revenue requirement amended pursuant to clause 6.21.2(3) to reflect a capital contribution allowed pursuant to clause 6.21.2(2) and calculated based on the application of ESC Guideline No. 14. In this way UED's proposed approach is consistent with the previously applicable regulatory approach.

12.2 AER's Draft Decision on Service Classification

Page 38 of the Draft Decision states that the AER accepts UED's classification of new connections requiring augmentation works as standard control services.

12.3 UED’s response to the AER’s Draft Decision on Service Classification

UED welcomes the AER’s acceptance of the classification of new connections requiring augmentation works as standard control services. This revised proposal gives effect to the AER’s draft decision in this matter.

13. Energy, peak demand and customer number forecasts

Key messages

UED's original Regulatory Proposal explained that:

- UED's energy sales in the current regulatory period have declined and are lower than forecast in the 2006 EDPR.
- Given Federal and State Government initiatives aimed at reducing emissions, UED's energy sales over the forthcoming regulatory period are forecast to decline at an average rate of 1 per cent per annum.
- The maximum demand on UED's network has continued to increase over the current regulatory period, demonstrating the combined effects of increasing penetration of air conditioners and higher ambient summer temperatures.
- Maximum demand (at the 50^{th} percentile forecast) is expected to increase at an average annual rate of 2.3 per cent.
- Maximum demand (at the 10^{th} percentile forecast) is expected to increase at an average annual rate of 2.8 per cent.
- UED's total customer numbers are expected to grow at an average annual rate of 0.6 per cent.

The AER's draft determination argues that:

- Maximum demand forecasts for the forthcoming regulatory period are generally consistent with historic trends.
- On balance NIEIR's maximum demand forecasting methodology appears to be reasonable.
- NIEIR's approach to forecasting energy exhibits elements of good forecasting methodology although lacks transparency.
- UED's forecasts are now out of date and a new forecast should be provided as part of the revised proposal.
- The AER has made post modelling adjustments to UED's forecast to reflect the impacts of:
    a. population growth;
    b. MEPS;
    c. CPRS;
    d. the AER's belief that it is unreasonable to assume any impact arising from the AMI in the forthcoming regulatory control period; and
    e. other initiative and schemes.

In this Revised Regulatory Proposal, UED explains that:

- The adjustments that the AER makes to UED's energy forecasts lead to growth projections for UED that are in excess of the bounds of reasonableness. UED's energy sales growth rate has been approximately zero over the 2006 to 2010 regulatory period. The AER's projection of an annual energy sales growth rate of 2.6 percent is manifestly inconsistent with recent actual empirical data and reasonable future projections of the impact of further energy conservation initiatives.

- The forecast methodology and the forecasts proposed by UED are practical and prudent for a capital intensive business and incorporate a reasonable approach to assessment and quantification of uncertainty and risk as part of UED's normal' business planning processes.

- Both the Office of the Regulator-General's (ORG) Final Determination for the 2001-05 electricity distribution price review and the Essential Services Commission's (ESC) Final Determination for the 2006-10 electricity price review explicitly recognised and acknowledged that UED and other distributors had adopted reasonable assumptions and methods for developing forecasts of customer numbers, energy consumption and peak demand – even though the ESC considered the assumptions to contain elements that were (in the ESC's view) 'conservative'.

- The ESC explicitly recognised and accepted that it was appropriate to accept forecasts of customer numbers, energy consumption and peak demand that *may under-estimate growth ...* (even though) ... *this is likely to provide the distributors with more revenue over the period than the revenue requirement* ... (because) ... *on balance, this is a more preferable outcome than not earning the revenue requirement, which might be the case if the Commission were to adopt* (the less 'conservative' assumptions of) *NIEIR's high case*.

- By comparison, the views and opinions expressed by the AER in the *Draft Decision* suggest a bias at odds with the regulatory precedent established by the ORG and ESC.

- The forecasts adopted by UED for the 2010-15 period are consistent with UED's 'normal' business planning processes and also consistent with the approach and methodology endorsed by the ORG in 2000 and the ESC in 2005-6.

- UED's forecasts utilise output from NIEIR's modelling that incorporate reasonable assumptions, including assumptions that reflect the substantial changes in Government policy since 2005 that are explicitly intended to reduce energy consumption in all sectors of the economy.

- Both the Australian and Victorian Governments have stated publicly that they are either adopting new policies or modifying existing policies with a specific intention of achieving even more substantial energy efficiency improvements in the economy; and both Governments are reviewing other existing policies with the intention of contributing to that same objective within the next regulatory period.

- Each of the existing policies, and the announced changes to policy, are supported by Regulatory Impact Statements (RIS) conducted in compliance with Council of Australian Governments (COAG) *Best Practice Regulation Guide*. Each of these RISs presents an estimate of the expected energy reductions.

- The cumulative RIS estimates of energy savings are material and were intended to impact on energy consumption in the 2005-10 period. Confirmed policy changes, and others where reviews have been confirmed by Governments are intended to intensify those impacts in the 2010-15 period and beyond.

- Given these circumstances, it is incongruous for the AER to assume the suite of energy efficiency policies implemented by COAG the and the Victorian Government will have only a minor impact on energy consumption for customers connected to UED's distribution network.
- UED has engaged NIEIR to provide a set of updated forecasts to reflect latest economic conditions.
- The post modelling adjustments made by the AER are incorrect, and UED has provided, in this Revised Regulatory Proposal, details of more appropriate and reasonable adjustments.
- The forecasts provided by UED in this Revised Regulatory Proposal reconcile to the latest AEMO forecasts.
- The revised forecasts confirm that UED's energy volumes over the forthcoming regulatory period are expected to decline, at an average rate of 0.4 per cent per annum, slightly lower than NIEIR's initial forecast.
- UED accepts that the revised forecasts contain elements of uncertainty. Energy volumes could be significantly higher than NIEIR's forecasts if consumers seek higher levels of service and comfort than assumed in the respective RISs. Energy volumes could also be significantly lower than this forecast if:
    - NIEIR's assumptions about the effectiveness of the suite of energy efficiency policies prove to be too modest (e.g. builders and home owners voluntarily adopt energy efficiency measures that exceed mandatory standards);
    - consumers respond to continuing public messages reinforcing the environmental (and cost reduction) benefits of energy efficiency policies (e.g. and mirror outcomes in the water sector where consistent messages promoting the benefit so water savings demonstrate strong resilience); and
    - due to impacts of further or modified energy efficiency policies that have been announced but are not included in NIEIR's modelling.
- The revised forecasts also confirm that peak summer demand will continue to grow at a substantially higher rate than energy consumption, primarily from continued increases in air conditioning penetration in the Residential sector, and UED's total customer numbers are expected to grow less than Victoria's population at an average annual rate of 0.8 per cent.

13.1 Recap on UED's Regulatory Proposal

UED's initial Regulatory Proposal explained that UED's forecasts were developed with the assistance of NIEIR. NIEIR are recognised experts in the field of load forecasting and are also engaged by AEMO to forecast load for Victoria.

In addition to engaging NIEIR, UED sought expert advice from AECOM on the likely effects of climate change on UED's future load. NIEIR factored AECOM's recommendations and conclusions into its assessment of UED's load forecast.

Finally, UED reconciled the advice and forecasts from NIEIR with its own internal ('bottom up') assessment of growth for individual major network components.Table 13-1 in UED's initial Regulatory Proposal compared actual/estimated energy distributed against the forecasts in the 2006 EDPR. The table (reproduced below) shows:

- The variance between forecast and actual energy consumption in each year is small, indicating that UED and NIEIR have a good track record in forecasting energy volumes; and
- Actual load has declined over the course of the regulatory period and is estimated to be below the 5-year aggregate volume by the end of 2010. The decline in UED's load growth partly reflects the low rate of customer growth in UED's territory, which is the lowest across the Victorian businesses, and the compounding impact of increasingly demanding energy efficiency policies.

Table 13-1: Comparison of actual and estimated load to the 2006 EDPR benchmark load – GWh

Year Ending 31 December						
Category	2006	2007	2008	2009	2010	Total
	Actual				Estimated	
Actual/estimated energy	7,814	7,888	7,912	7,814	7,788	39,216
2006 EDPR forecast	7,665	7,817	7,943	8,046	8,161	39,632
Variance (GWh)	149	71	- 31	- 232	- 373	-416
Variance (%)	+1.9	+0.91	-0.39	-2.92	-4.57	-1.05

UED's initial Regulatory Proposal referred to the following State and Federal Government initiatives that aim to reduce emissions through lower energy consumption:

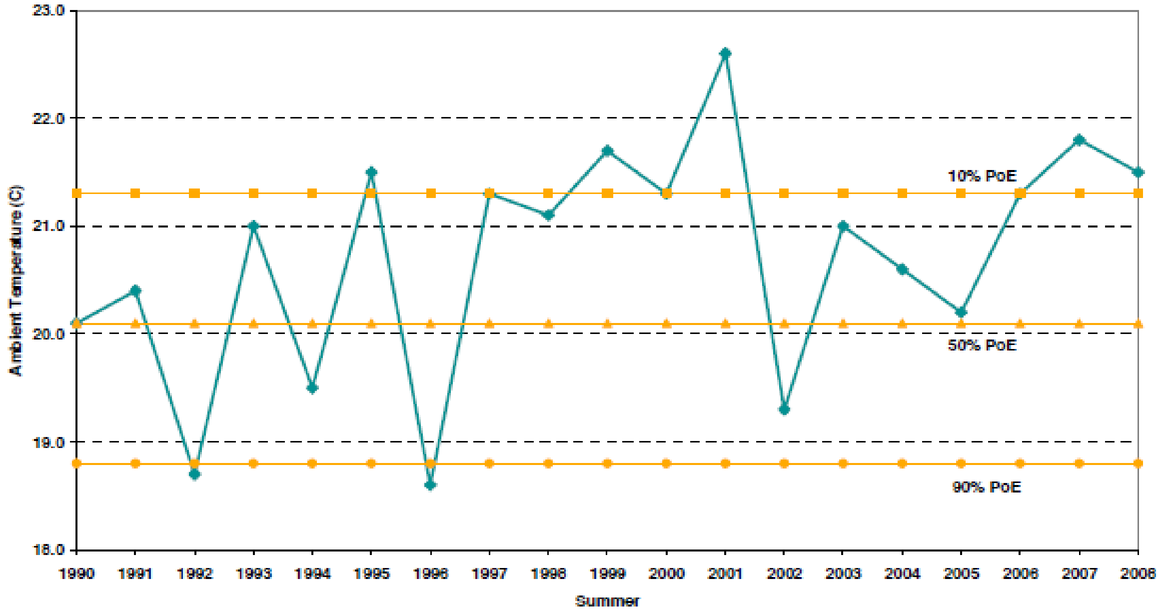
- the Carbon Pollution Reduction Scheme ("CPRS");
- minimum Energy Efficiency and Performance Standards for appliances (MEPS);
- 1 watt standby power in appliances;
- Federal insulation program;
- photovoltaic generation;

- Victorian Energy Efficiency Target;
- residential and commercial building standards; and

UED's initial Regulatory Proposal also explained that, if these energy efficiency and climate change policies are fully implemented, it is projected that energy sales will reduce at an average annual rate of 0.2 per cent under the medium economic growth scenario over the period 2008-16 compared with average annual rise in summer peak demand of 2.6 per cent (under medium economic growth scenario with 10 per cent PoE) over the same period. In contrast to energy growth, the growth in summer peak demand would continue mainly due to the increasing penetration of air conditioning units that would be less affected by energy efficiency and climate change policies.

UED's initial Regulatory Proposal also highlighted that recent increases in summer temperatures were leading to record demands on UED's network. The constraints in UED's network are generally related to the thermal capacity of plant in summer, when network loading is generally at its highest and plant rating is at its lowest. Hence summer maximum demand forecasts become an important trigger for capacity planning for UED.

Figure 13-1: Average summer monthly ambient temperatures, 1990 - 2008[98]



UED's initial Regulatory Proposal concluded that:

- UED's energy sales over the forthcoming regulatory period are forecast to decline at an average rate of 1 per cent per annum.
- Maximum demand (at the 50th percentile forecast) is expected to increase at an average annual rate of 2.3 per cent.
- Maximum demand (at the 10th percentile forecast) is expected to increase at an average annual rate of 2.8 per cent.
- UED's total customer numbers are expected to grow at an average annual rate of 0.6 per cent.

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98 This presentation of temperature data (and the text following) assumes that the historical record forms a statically consistent data set. This is a standard assumption in the energy sector. However, UED notes that there is now general acceptance by Government agencies, regulators and water service providers across Australia that the historical record may not represent a consistent data set for the purposes of water supply and demand planning.

The water sector is moving to 'scenario' planning where scenarios with shorter periods of climate data are compared with planning analysis based on the full historical record.

The ESC and other jurisdictional regulators have accepted the outcomes of short period 'scenario' planning as a basis for regulatory water service prices.

Application of similar planning scenarios to the energy sector would produce higher temperatures for each PoE category and show that extreme peak demand events were closer to the 50% PoE than indicated in the above figure. That is, UED's peak demand forecasts would be more likely to occur than indicated in this diagram.

13.2 NIEIR's Modelling Method

UED accepts the AER's comment that NIEIR's explanation of its modelling methods can be less than transparent. This is due to:

- the complexity of the economy that NIEIR is modelling;
- the complex nature of the modelling process itself, which requires inter-linking of a number of discrete component models;
- NIEIR's desire to protect its intellectual property; and
- the fact that output from the model is generally accepted by NIEIR's clients as input into their own specific and coherent business planning frameworks.

To assist in improving transparency of NIEIR's modelling, UED has attempted to explain briefly (where relevant in this response) how various outcomes are achieved in the NIEIR modelling process.

13.3 The role of NIEIR's forecasts in UED's business planning process

As requested by the AER, UED has provided a revised forecast to reflect more up to date economic conditions. These forecasts have been provided by NIEIR and have been prepared in a manner consistent with those provided in the initial Regulatory Proposal.

Incorporation of NIEIR's forecasts into a robust business planning process requires 'interpretation' of the modelling output. That is, UED does not rely solely on the output of NIEIR's modelling when preparing its business plans or Regulatory Proposals.

As a general example of why this 'interpretation' is necessary, UED notes that output from the model is disaggregated by local government area. Some local government areas overlap more than one distributors' area, so NIEIR's model further distributes outputs allocated to local government areas using a Local Government Area Percentage factor derived by comparing the distributor's area to each local government area.[99] The percentage assigned to UED in NIEIR's modelling are:

- Bayside 100.0
- Frankston 68.0
- Glen Eira 100.0
- Greater Dandenong 99.0
- Kingston 100.0
- Manningham 98.0
- Monash 100.0
- Mornington Peninsula 100.0

[99] p. 111, *Appendix A: Reconciliation of Local Government Areas with the United Energy distribution area, Electricity sales and customer number forecasts for the United Energy region to 2019*, NIEIR, June 2010.

- Port Phillip 41.0
- Stonnington 49.0
- Whitehorse 100.0

UED's service territory covers 100 per cent of the Bayside local government area, but only 41 per cent of the Port Philip local Government area. NIEIR's Local Government Area Percentage factor (being area based) takes no account of differences in customer mix (which would affect loadings on individual network components) within the local government area. This means, for example, that even if NIEIR's models 'accurately' modelled new house construction for Port Philip local government area, it would not 'translate' into an 'accurate' forecast of housing building activity (or network loading) within either CitiPower's or UED's distribution area unless the building activity was distributed evenly across the local government area, or occurred in particular locations in each distributors' area in exact proportion to their individual shares of the Port Philip local government area.

Accordingly, it is UED's considered view that it is appropriate, reasonable and prudent to use NIEIR's modelling output as a major, but nonetheless only one, input in developing its business plans and Regulatory Proposals.

UED manages incorporation of NIEIR's modelling output into its business planning process, and its Regulatory Proposals, in part by comparing previous modelling forecasts with actual outcomes, regularly reviewing its own internal business plans using observed data and integrating all this with 'bottom up' planning information linked to individual network elements. This process produces a Regulatory Proposal that is consistent with a practical and prudent 'business plan' that is also suitable to guide the business within a regulatory period.

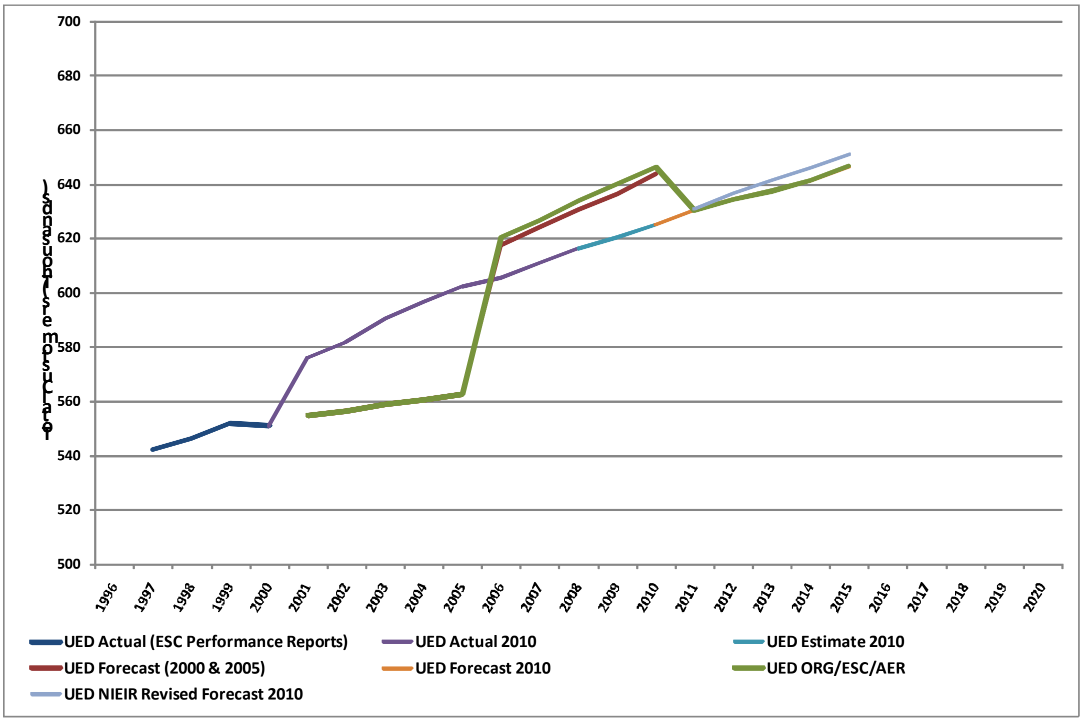
The outcomes from such prudent business processes is fed back to NIEIR and used to improve subsequent modelling forecasts. The 'testing and feedback' in this process means that the forecasts included in UED's Regulatory Proposals are practical and prudent for a capital intensive business and incorporate a reasonable approach to assessment and quantification of uncertainty and risk.

The uncertainty that remains in the forecasts still represents a material business risk, the quantum and nature of which can be illustrated in the following diagrams, which compare data from:

- UED's initial Regulatory Proposals[100] for each of the price reviews in 2000, 2005 and 2010;
- The 'regulatory allowances' incorporated into the ORG's 2000 Final Determination, the ESC's 2006 Final Determination, and the AER's Draft Decision;
- Monitoring and reporting of outcomes in accordance with Guidelines and Regulatory Information Notices issued by the ORG, ESC and AER.

[100] The initial Regulatory Proposals are (typically) modified incrementally and progressively during the price review process as comments from the regulators are taken into account.

Figure 13-2: Comparison of Total Customer Number Data

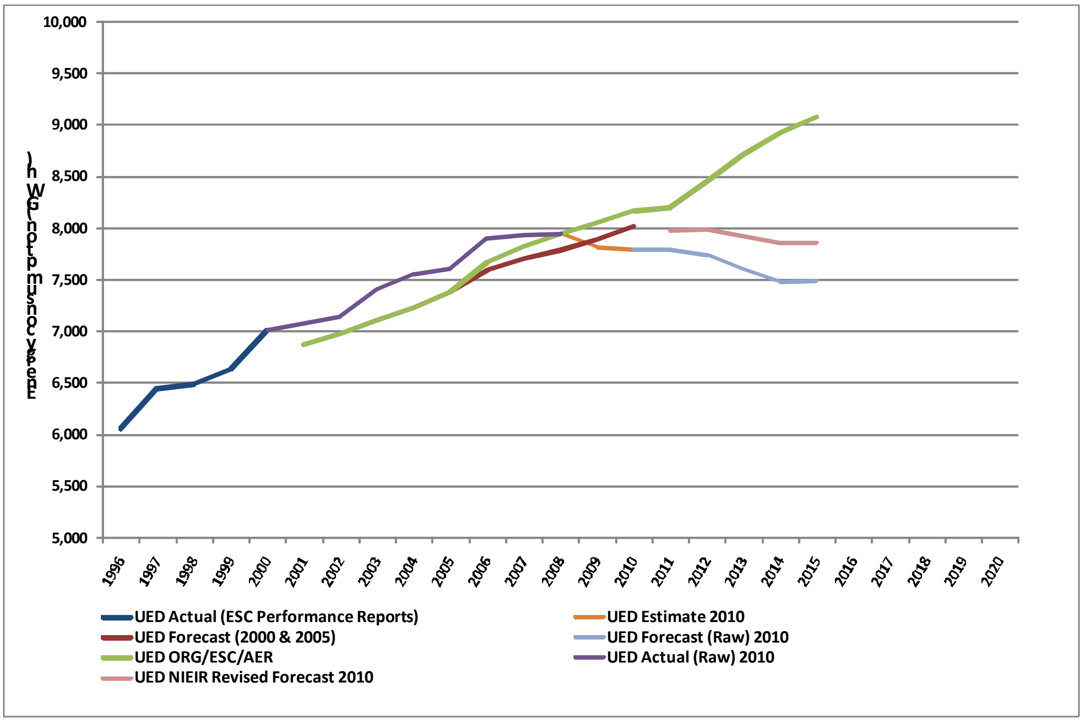


In respect of customer number forecasts, the data in Figure 13-2 illustrates:

- The NIEIR modelling under-forecast customer numbers by as much as -7 per cent in the 2001-05 period (based on the forecasts in UED's <u>initial</u> Regulatory Proposal that were accepted by the ORG), but is expected to over-forecast by as much as +3.2 per cent at the end of the 2006-10 period.
- The modelling output for both periods appears to show a strong correlation with recent past trends. As UED noted in its initial 2005 proposal, NIEIR forecast much lower customer numbers than actual in the 2001-05 period primarily because Victoria's economy was stronger than anticipated in that period; and this stimulated increased "internal" migration to Victoria and building activity (which added to economic activity). The higher forecast customer numbers in the current (2006-10) period reflect the fact that the increased economic activity of the 2001-05 period was not sustained.
- Neither of these trends was anticipated by NIEIR, UED, the ORG, the ESC (or their respective consultants) or the Victorian Treasury at the time the forecasts were prepared.

On the basis of these outcomes, it is UED's view that it is reasonable for the AER to accept UED's forecast methodology of customer numbers on the basis that it produces a practicable and robust forecast that is consistent with the requirements of the National Electricity Rules and the National Electricity Law.

Figure 13-3: Comparison of Energy Volume Data

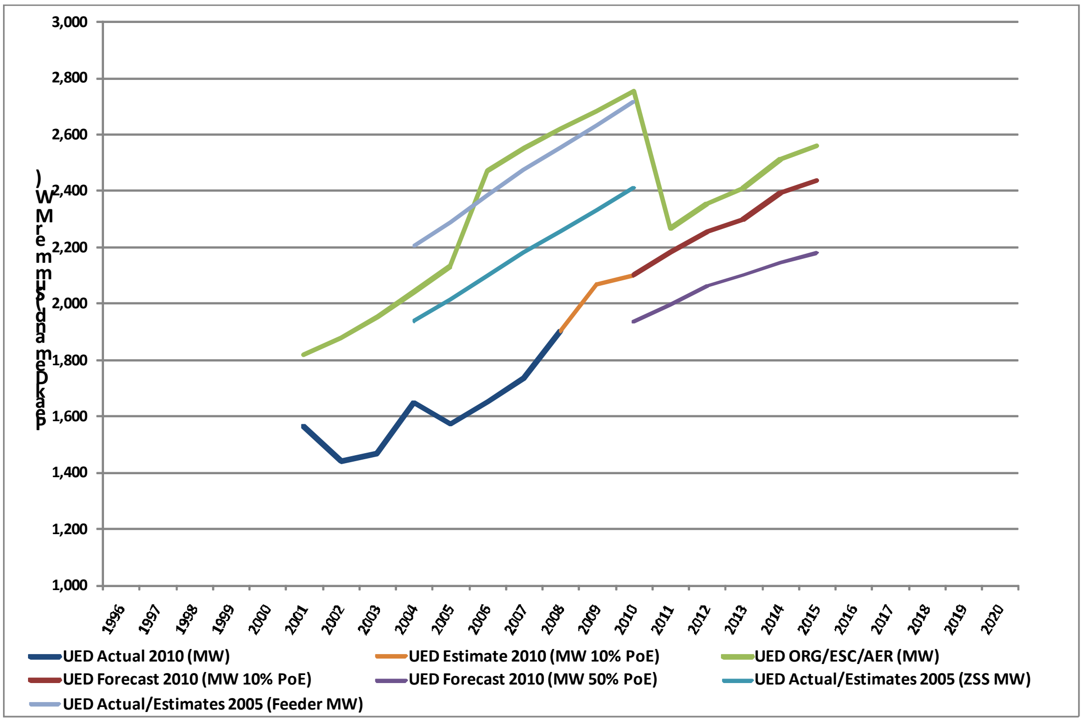


In respect of energy volume forecasts, the data in Figure 13-3 illustrates:

- NIEIR's forecasting energy volumes has been closer to actual data than forecasting of customer numbers. Forecasts for the 2001-05 period were within -4.5 per cent of actual. Forecasts for the 2006-10 period are estimated to be within -4.1 per cent and +2.8 per cent.
- This outcome demonstrates the strength of NIEIR's modelling that links a range of input parameters to produce integrated forecasts with a reasonable correlation between overall economic activity and electricity consumption.

On the basis of these outcomes, it is UED's view that it is reasonable for the AER to accept UED's forecast methodology of energy on the basis that it produces a practicable and robust forecast that is consistent with the requirements of the National Electricity Rules and the national Electricity Law.

Figure 13-4: Comparison of Peak Demand Data



In respect of peak demand forecasts, the data in Figure 13-4 illustrates:

- The challenges in presenting data on peak demand, when the format specified for reporting varies (being either 'coincident peak', 'feeder peak' or 'zone substation peak') and the actual peak demand is heavily influenced by summer maximum temperature and the day of the week (or month) on which that maximum temperature occurs.

- NIEIR's modelling output requires considerable 'interpretation' to derive peak demand forecasts that are meaningful in developing a coherent business plan or Regulatory Proposal.

- The metrics that the data in Figure 13-4 describes are not particularly useful in developing a coherent business plan because peak demand is critical in UED's system only in so far as it impacts on discrete network elements that are operating at or near their design limits.

- Given that these metrics are of little relevance to UED's business planning processes, there appears to little value in reporting them; and even less value in the AER (or its consultants) committing significant resources to examining how the numbers are derived.

- UED acknowledges that understanding of how the forecast and actual numbers are derived for the key network components may assist the AER's understanding of relevant issues. UED also assumes that this is why, for the first time, an economic regulator and its consultants produced estimates of 'peak demand adjustments' for 15 of UED's 45 zone substations.[101]

- The potential value to the AER of examining the relevant details in UED's latest 2009 Distribution System Planning Report. Detailed information in this Planning Report shows that the overwhelming majority of UED's Zone Substations are forecast to operate above N-1 loading during the 2010-15 regulatory period; and that the probability-weighted Customer value of lost load will increase markedly unless UED is able to invest appropriately in system reinforcement. The information in the Planning Report also emphasises that peak demand is only important for critically loaded individual network elements at the feeder, zone substation level and terminal station level – and peaks in each of these elements may occur at different times in a single day, or even on different days in a single summer.

Each of the examples above illustrate that the outcomes of the modelling process used as input to UED's initial Regulatory Proposals was not improved materially by increasingly detailed scrutiny of successive regulators and their consultants. The ORG accepted the forecasts proposed by UED, after scrutiny by Sinclair Knight Mertz Pty Ltd; and the ESC required only minor adjustments (compared to the differences between the modified forecasts and actual) after much more detailed scrutiny by McLennan Magasanik Associates Pty Ltd and then subsequently by the ESC's own officers.[102] But the outcomes still varies significantly from the forecast.

The most useful outcomes from the scrutiny of previous regulators were:

- Both the Office of the Regulator-General's (ORG) Final Determination for the 2001-05 electricity distribution price review and the Essential Services Commission's (ESC) Final Determination for the 2006-10 electricity price review explicitly recognised and acknowledged that UED and other distributors had adopted reasonable assumptions and methods for developing forecasts of customer numbers, energy consumption and peak demand – even though the ESC considered the assumptions to contain elements that were (in the ESC's view) 'conservative'.

- The ESC explicitly recognised that it was appropriate to accept forecasts of customer numbers, energy consumption and peak demand that *may under-estimate growth and* (that) *this is likely to provide the distributors with more revenue over the period than the*

[101] UED notes that the AER did not undertake a similar critical assessment of individual zone substation loadings in recent reviews of the NSW and QLD distribution systems. UED is also concerned that neither the AER or its consultants has sufficient technical expertise to undertake such detailed analysis in a meaningful and credible way.

[102] UED notes that the ESC 'put aside' many of MMA's conclusions and recommendations, noting that it had *'some reservations over MMA's findings, in that it was not always clear what information and considerations MMA had relied on to make its judgement about concerns over some of the methodology and quantifications that NIEIR had used'* (pp. 134-135, *Final Decision Volume 1- Statement of Purpose and Reasons*, ESC, October 2006).

UED also notes that the ESC stated that '*In undertaking this review, the Commission has met with NIEIR and visited its premises to view the NIEIR model and assessed the assumptions that NIEIR has used against other publicly available information sources*' (p. 138, *Op Cit.I)*.

These features of the ESC's review presumably aided understanding of the complex modelling undertaken by NIEIR and assisted the ESC's understanding of how each distributor had applied NIEIR forecasts to its own business planning requirements.

> *revenue requirement* (because) *on balance, this is a more preferable outcome than not earning the revenue requirement, which might be the case if the Commission were to adopt* (the less 'conservative' assumptions of) *NIEIR's high case*.[103]

By comparison, the views and opinions expressed by the AER in the Draft Decision suggest a bias[104] at odds with the regulatory precedent established by the ORG and ESC. For example, in respect of comments on variations between forecast and actual figures, the AER states:

> '*The data presented in figure 5.2 above is consistent with the perverse incentives of weighted average price cap form of control where the DNSPs are able to achieve significant windfall gains by under forecasting energy consumption at the time of each price review. The data underlying figure 5.2 shows that over 2001–08 (that is, where actual energy sales and approved forecasts are available) the Victorian DNSPs where actual energy sales and approved forecasts are available) the Victorian DNSPs have distributed 3,246 GWh more than the forecasts ultimately relied upon by the ESCV. The AER estimates that these additional sales have resulted in a $144 million or 1.2 per cent increase in revenues for the Victorian DNSPs over these nine years.*'[105]

The AER has failed to recognise that:

- UED is very likely to finish the regulatory period with total energy volumes at or below the aggregate 5-year forecast (therefore the additional GWhs referred to above are the product of other Victorian distributors); and
- the risk associated with the uncertainty that remains in the forecasts resides ultimately with distributors.

Moreover the AER has not satisfied the responsibility it bears under the National Electricity Rules that before it not accept UED's customer number forecasts those forecasts must not be a "realistic expectation"; UED's forecasts are realistic. In addition, the required balancing of the economic costs and risks of under and over investment, and over and under utilisation, in UED's network favours the adoption of UED's forecasts. Moreover, the AER is reminded that UED must be provided with a reasonable opportunity to recover at least the efficient costs UED incurs in providing direct control network services. In relation to these revenue and pricing principles, the conclusions of the ESC are instructive.

13.4 The impact of Government energy efficiency policies

As noted in the re-cap above, UED's initial Regulatory Proposal outlined areas of impact on its forecasts and business planning processes that arise from a suite of policies implemented by the Australian Government in compliance with agreements made under the

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[103] p. 149, *Electricity Distribution Price Review 2006-10 - October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final Decision Volume 1- Statement of Purpose and Reasons*, ESC, October 2006

[104] The AER's bias is also illustrated by the different approach adopted in examining proposals put by NSW and Queensland distributors (see Footnote 101 above).

[105] p. 84, *Victorian Draft Distribution Determination—Draft Decision*, AER, June 2010.

auspices of the Council of Australian Governments (COAG) and separately by the Victorian Government.

NIEIR's modelling included estimation of the impacts of these policy areas broken down into the following categories.

- MEPs lighting
- Standby power
- Insulation
- Photovoltaics
- VEET
- Hot water
- MEPs air conditioners
- 6 star building standards
- Electric cars (off peak)
- Impact of advanced metering infrastructure.

UED's response to the AER draft decisions on the impact of each of these matters is dealt with later in this submission.

However, UED also notes that in analysis of the issues relevant to these policy impacts, the AER and ACIL Tasman referred to Regulatory Impact Statements[106] only in respect of MEPS for lighting.

UED's forecasts utilise output from NIEIR's modelling that incorporate reasonable assumptions, including assumptions that reflect the substantial changes in Government policy since 2005 that are explicitly intended to reduce energy consumption in all sectors of the economy. Both the Australian and Victorian Governments have stated publicly that they are either adopting new policies or modifying existing policies with a specific intention of achieving even more substantial energy efficiency improvements in the economy; and both Governments are reviewing other existing policies with the intention of contributing to that same objective within the next regulatory period. For example:

- The Victorian Minister for Planning announced on 30 April 2010 that 6 Star building standards would be applied to new homes, multi-unit developments and renovations/extensions from May 2011. The Minister's Press Release states explicitly that "*This has not only meant that 35,000 homes built each year are 50 per cent more efficient than their typical Two Star predecessors but the expansion enabled a further 40,000 homes each year to be upgraded.*"
- The Prime Minister's special taskforce on energy efficiency has concluded its report to the Prime Minister, calling on her to adopt a national energy efficiency target that

[106] UED's initial Regulatory Proposal referred to RISs only in respect of Mandatory Energy Performance Standards (MEPS) and the energy (appliance) rating labelling scheme.

(the taskforce says) will lead to bans on many energy-sapping appliances being sold in Australia.

- The Victorian Department of Primary Industries has investigated a range of new activity categories to be included in the Energy Saver Incentive (VEET) scheme and completed a Position Paper that provides detail on the possible new activities that are being considered for inclusion in the Victorian Energy Efficiency Target (VEET) regulations.

Each of the existing policies, and the announced changes to policy, are supported by Regulatory Impact Statements (RIS) conducted in compliance with Council of Australian Governments (COAG) *Best Practice Regulation Guide; and e*ach RIS presents an estimate of the expected energy reductions.

In an effort to assist the AER's understanding of the potential impacts of these policies, UED has prepared a summary of energy savings estimates developed in support of these policy initiatives. This summary is shown in Table 13-2 and Table 13-3 below.

The AER should note that figures in each RIS have been used to develop indicative savings estimate for Victoria during the forthcoming regulatory period, pro-rated based on Victoria's share of national consumption.[107] This methodology assumes a gradual reduction in Australian electricity generation emissions intensity (used to convert CO_2 savings to GWh equivalent). Where the RIS has provided multiple scenarios, the base scenario, or average of likely scenarios, has been used and estimated annual savings reported in the RIS have been apportioned over the regulatory period assuming a flat profile for simplicity.

[107] Victoria's share of national consumption based on ABARE data is 2223.4% (ABARE, 2008).

Table 13-2: Minimum Energy Performance Standards (MEPS) Regulations in Australia - Overview[108]

MEPS	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Refrigerators and freezers	From 1 October 1999. Revised 1 January 2005 and 1 April 2010.	Decision RIS (October 2008) • Refrigerators and freezers make up 13.4 per cent of consumption in Australia (estimate for 2005). • Set to decrease to 9.3 per cent in 2020. • AU wide expected savings by year (2010: 7 GWh/yr, 2015: 54 GWh/yr, 2020: 106 GWh/y). • Projected 225,446 refrigerator sales (total stock) in VIC by 2015, assumed 16 year life. • Projected 24,436 freezer sales (total stock) in VIC by 2015, assumed 20 year life.	54 GWh Cumulative 2010 to 2015	11 GWh

108 http://www.energyrating.gov.au/meps1.html

MEPS	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Mains pressure electric storage water heaters	From 1 October 1999); small mains pressure electric storage water heaters (<80L) and low pressure and heat exchanger types (from 1 October 2005).	Consultation RIS (December 2009) • Hot Water accounts for nearly 23 per cent of the energy used in Australian households in 2008 • 11.8 Mt CO_2 cumulative savings between 2011 and 2020 Note: 1: 5 Star and 6 Star building regulations mandate exclusion of electric water heaters where mains gas is available (and gas water heating is required to achieve Star rating of building shell). 2: NIEIR have fa ctored in the exclusion of EHW where mains gas is available, assuming a 6.7 per cent replacement rate (all electric in gas areas will be replaced after 15 years).	11.8 Mt CO_2 Cumulative 2011 to 2020	1,745 GWh
Three phase electric motors (0.73kW to <185kW)	From 1 October 2001. Revised April 2006.	Draft RIS for proposal (Nov 2003), unable to find more recent RIS: • Measures required about 70 per cent of the then existing models to be withdrawn from the market. • The energy savings compared with BAU were expected to peak in 2012 at about 570 GWh/yr (Australia wide). • MEPS (applicable from April 2006) range from about 70 per cent efficiency (0.73 kW, 8 pole motors) to about 95 per cent efficiency (185 kW 8 pole motors).	570 GWh Annual in 2012	666 GWh

MEPS	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Single phase air conditioners	From 1 October 2004. Revised 1 April 2006, 1 April 2007, 1 April 2008, 1 April 2010 and 1 April 2011.	Consultation RIS (June 2010) • AC sales increasing from 210,000 units in 2010 to 230,000 in 2015. Approx 70 per cent units to Residential (households), 30 per cent Commercial/Industrial. • Total households with AC increasing from 1.775M in 2010 to 1.956M in 2015 (cf 1.300M in 2000). Increase in penetration 2010-2015 (~2 per cent /year) higher than population and household growth. • Average life 15-20 years. • Average demand not specified. • AC penetration has increased from 30.9 per cent of households in 1999 to 48.9 per cent in 2008. • Heating and Cooling efficiency to increase by 10 per cent from April 2010 (and, recommended, by a further 10 per cent in 2014). • Energy impact of Commercial/Industrial AC "outweighs" Residential. • No details of energy savings for VIC. Energy savings for AUS projected at 425GWh (compared to 19,000GWh/yr by 2015 with no change in MEPS).	425 GWh Cumulative 2011 to 2015	99 GWh
Three phase air conditioners up to 65kW cooling capacity	From 1 October 2001. Revised 1 October 2007, 1 April 2010 and 1 April 2011.	See comments on Single Phase Air conditioners above.	See above	See above

MEPS	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Ballasts for linear fluorescent lamps	From 1 March 2003).	Draft RIS for public comment (Feb 2001), unable to find a more recent RIS: • At time of RIS, 21 per cent of fluorescent lighting energy was related to control ballast losses – about 2,540 GWh • Recommended options (2a, 2c – not sure which one was adopted) energy savings from 2001 – 2015 projected to be 8 TWh to 11.5 TWh. Note: In addition to MEPS, ballasts also have to be marked with an energy efficiency index (EEI).	8 TWh to 11.5 TWh Cumulative 2001 to 2015	759 GWh
Linear fluorescent lamps	From 1 October 2004 for 550mm to 1500mm inclusive with a nominal lamp power >16W.	Final RIS (December 2003): • Estimated that half of the halophosphate lamp stock is eliminated in the first four years of MEPS (equal to the average lifetime of halophosphate lamps). • 0.5 to 3.1 Mt CO_2e cumulative savings between 2005 and 2020. Note: Preliminary estimate of savings for VIC around 400 GWh.	0.5 to 3.1 Mt CO_2e Cumulative 2005 to 2020	131 GWh

MEPS	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Distribution transformers	From 1 October 2004 for 11kV and 22kV with a rating from 10kA to 2.5MVA.	Proposal to increase MEPS Levels (Technical Report October 2007): • Proposal to increase local transformer efficiency level MEPS to new level consistent with international levels. • Example provided for 1000 kVA transformer, 16 kWh daily energy saving (5.8 MWh / annum).	n/a	n/a
Commercial refrigeration	From 1 October 2004 for self contained and remote systems.	Draft strategic plan (October 2009): • Non-domestic refrigeration consumed approximately 13,400 GWh in 2008 (Australia). • Responsible for 13.7 Mt CO_2. • Strategy includes a range of policy measures, including the provision of information and voluntary and regulatory initiatives. • Strategy is expected to reduce annual consumption by 14 per cent in 2020 (3,300 GWh) or 2.5 Mt CO_2. • Timeline: it is expected that regulatory policy measures require a period of between 2-3 years (minimum) from the commencement of development tasks to the time they come into force. Draft RIS for public comment (February 2004): • Proposed measure expected to achieve GHG abatement between 1.5 to 2.4 Mt CO_2 equivalent (approximately 1,500 to 2,400GWh/year).[109]	n/a	n/a

[109] This potentially overstates the GWh savings (e.g. if the RIS estimate is counting other GHG savings – methane for example – in the CO_2 equivalent figure.

MEPS	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Incandescent Lamps	From November 2009 (Halogen transformers from 2010).	Decision RIS on proposed MEPS for incandescent lamps, compact fluorescent lamps and voltage converters (May 2009): • Import restrictions on GLS lamps commenced from 1 February 2009 • Point of sale MEPS for GLS, extra low voltage halogen, non reflector and CFL non reflector applied from November 2009 • Additional measures on other low efficiency lamps are planned but subject to review • Nationwide cumulative energy saving of 30,305 GWh from 2008 to 2020	30,305 GWh Cumulative 2008 to 2020	2,723 GWh
Compact Fluorescent Lamps	From November 2009 (November 2008 for certain types).	See comments on Incandescent Lamps above.	See above	See above
External Power Supplies	From 1 December 2008.	Second consultation RIS (December 2007): • In Australia, external power supplies' standby energy and conversion losses consumed an estimated 845 GWh (2004). • Annual sales growth scenarios modelled between 5 per cent (conservative) growth to 6 per cent-11 per cent (high industry forecast) growth. • Energy savings estimated at between 8,536 GWh to 11,459 GWh (2007 to 2025)	8,536 GWh to 11,459 GWh Cumulative 2007 to 2025	614 GWh

MEPS	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Set top boxes	From 1 December 2008.	Decision RIS (June 2008): • Australian electricity consumption of STB for 2006 was estimated to be 500 GWh/yr. • Base case energy savings of 1,561 GWh for Australia (to 2020).	1,561 GWh Cumulative 2009 to 2020	152 GWh
Televisions	From 1 October 2009.	Final RIS (May 2009): • Tier 1 from 1 October 2009. • Tier 2 (more stringent 3 or 4 star MEPS) from 1 October 2012. • Energy saving from 2007 to 2020 (Australia) of 34.1 TWh (Tier 2 at 3 stars) to 40.1 TWh (Tier 2 at 4 stars).	34.1 TWh to 40.1 TWh Cumulative 2007 to 2020	3 GWh
Commercial Building Chillers	From July 2009	Decision RIS (July 2008): • 2006 (Australia) consumption estimated to be 4.9 TWh/yr • Base case energy savings from 2007 to 2020 estimated as 2,862 GWh.	2,862 GWh Cumulative 2007 to 2020	239 GWh
Close Control Air Conditioners	From July 2009.	Decision RIS (December 2008): • Annual Australian electricity consumption from CCAC estimated to be 1,380 GWh/yr for the year 2006 • Base case energy saving of 1,748 GWh (from 2007 to 2020)	1,748 GWh Cumulative 2007 to 2020	146 GWh
Transformers and Electronic Step-down Converters for ELV Lamps	Proposed for October 2010	See comments on Incandescent Lamps above.	See above	See above

Table 13-3: Building standards[110] and Victorian Energy Efficiency Target (VEET) Regulations in Australia – Overview

Policy	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
Revised Energy Efficiency Requirements of the Building Code of Australia	May 2011	Decision RIS (December 2009) • Residential savings of 800 GWh in 2020 • Commercial savings of 1,379 GWh in 2020	**Residential** 800 GWh Annual in 2020 **Commercial** 1,379 GWh Annual in 2020	**Residential** 935 GWh **Commercial** 1,611 GWh

110 The RIS documents for the building standards were commissioned by the Australian Building Codes Board. The document posted on the ABCB Website is presumed to relate to the revision from 5 Start to 6 Star building standards. UED has not examined energy saving estimates prepared for the 5 Star RIS, since the NIEIR and AER arguments focuses more around the incremental saving of moving to 6 star.

Policy	Implementation dates	Summary of RIS energy savings estimates	RIS estimate of savings	Indicative savings for Victoria during regulatory period
VEET	1 January 2009	Consultation RIS (September 2008) • 0.78 Mt of average annual GHG abatement over the first scheme phase (2009 to 2011)	0.78 Mt CO_2 Annual	3,900 GWh

The total indicative energy savings for the 2010-15 period from the above tables is some 13,700 GWh[111] and given that the measures primarily target the residential and commercial sectors, it is reasonable to assume that a majority of savings would occur in distribution connected customers' premises.

UED does not assert that this figure represents a better or more accurate estimate of energy savings than the estimate produced by NIEIR, but it is a substantially higher value than NIEIR's estimate (of 5,716 GWh)[112] and does indicate the policy makers intention of achieving significant reductions (of around 8 per cent) when compared to total distribution energy volumes over the 2011-16 period. This information demonstrates that UED's forecast of energy savings are conservative when compared to estimates that underpinned Government policies. This demonstrates that UED has potentially erred significantly in favour of customers in its current forecast.

UED restates its view that the cumulative impact of energy savings arising from policies intended to impact on energy consumption in the 2005-10 period are sufficiently material to be taken into account in its business plans. Confirmed policy changes, and others where reviews have been confirmed by Governments are intended to intensify those impacts in the 2011-16 period and beyond; and despite the AER's doubts aboutthe impacts from the AMI roll-out, that program is also intended to impact both peak demand and energy consumption during the 2011-16 period.

Given these circumstances, it is incongruous for the AER to conclude that the suite of energy efficiency policies implemented by COAG and the Victorian Government will have only a minor impact on energy consumption for customers connected to UED's distribution network.

13.5 AER's draft determination and UED's Revised Regulatory Proposal

UED response to specific issues raised by the AER, and the relevant elements of UED's Revised Regulatory Proposal are outlined below.

In response to the AER's comments in the draft decision, UED has prepared revised energy forecasts. These have been incorporated into the RIN that accompanies this revised proposal.

The revisions are based on revised modelling undertaken by NIEIR. NIEIR's latest report is attached an as appendix to this Revised Regulatory Proposal submission.

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[111] The indicative energy savings in Table 13-2 and Table 13-3 do not include impacts from the home insulation or photovoltaic schemes, which together account for some 10% of NIEIR's estimate of energy efficiency policy impacts; and UED notes and endorses ACIL's conclusions that NIEIR has substantially underestimated the impact of the various incentives underpinning photovoltaic policy.

[112] Table 5.17, p. 100, *Victorian Draft Distribution Determination—Draft Decision*, AER, June 2010.

13.5.1 Customer Numbers

UED's customer number forecast provided as part of its initial Regulatory Proposal is provided in Table 13-4 below.

For comparative purposes, data from the AER's draft decision is also provided together with data from UED's Revised Regulatory Proposal, which is based on NIEIR's revised modelling.

Table 13-4: Customer number forecasts

	Year Ending 31 December				
Category	**2011**	**2012**	**2013**	**2014**	**2015**
UED's Initial Regulatory Proposal	630,194	634,296	637,563	641,373	646,457
AER Draft Decision	630,196	634,300	637,565	641,377	646,461
UED's Revised Regulatory Proposal	630,635	636,421	641,506	646,067	650,752

The AER correctly concluded that UED's customer growth is the lowest of all the Victorian DNSPs, reflecting the established nature of dwellings and businesses in UED's region (and a lower share of metropolitan growth corridor areas in UED's service territory).[113]

Over time, UED's share of total customers and total energy is forecast to decline compared to the other businesses as their networks and customer numbers grow at a faster rate than UED's.

UED also notes that in developing its forecasts NIEIR utilises detailed construction industry models to forecast residential customer numbers. These models are primarily driven by population growth and provide dwelling stock forecasts at the state level. Residential customer number forecasts for individual regions are based on a disaggregation of dwelling stock forecasts for Victoria, initially by local government area and then distribution business area. This regional allocation allows UED to incorporate the modelling output into its 'bottom up' assessments of connections, energy volumes and peak demand based on major network components.

13.5.2 Energy

UED's energy forecast provided as part of its initial Regulatory Proposal is provided in Table 13-7 below. For comparative purposes the AER's draft decision is also shown together with UED's revised proposal.

[113] Pages 83 of AER's Draft Decision

Table 13-5: Energy volume forecasts

Year Ending 31 December					
Category	**2011**	**2012**	**2013**	**2014**	**2015**
UED's submission	7,793	7,734	7,592	7,478	7,486
AER draft decision	8,193	8,444	8,710	8,921	9,072
UED's revised proposal	7,929	7,936	7,868	7,801	7,800

The benchmark for energy sales during the 2006-10 period that was contained in the ESC's *Final Determination* is 39,632GWh. These energy sales were based on an average growth rate of 1.3 per cent per annum. This compares to the most recent forecast (which includes actual data for four of the five year period) of approximately 39,350 GWh. This is a variance of less than one per cent.

Through a number of post modelling adjustments, the AER's draft decision provides for an annual growth rate of 2.1 per cent, which is the highest of all the Victorian businesses. This growth rate is not consistent with historical trends and is not consistent with UED having the smallest customer growth of all Victorian businesses (as confirmed in the AER's draft decision.)

UED's believes that the AER has made a number of errors in its draft decision and the remainder of this sub-section address various elements of the AER's draft decision that affect this forecast; and provide further substantiation of UED's forecast.

13.5.2.1 Forecasting methodology

The AER states that the NIEIR approach to forecasting generally exhibits elements of good forecasting. UED endorsees this conclusion. UED has used NIEIR as its preferred forecaster of energy and maximum demand for over 10 years. NIEIR have developed an excellent database over this time and are able to forecast UED's energy sales with sufficient accuracy to form the basis of a reasonable and prudent business plan. It is pleasing that the AER acknowledges the positive attributes of the forecasting methodology, despite having some concerns over transparency.

ACIL Tasman, in outlining the attributes of a best practice methodology, state the two of the key features of best practice modelling are:

- Incorporation of key drivers – including economic growth, population growth, growth in the number of households, temperature and weather related data (where appropriate), and the growth in the number of air conditioning and heating systems.
- Model validation and testing – including assessment of statistical significance of explanatory variables, goodness of fit, in sample forecasting performance of the

model against actual data, diagnostic checking of the old models, out of sample forecast performance[114]

Despite this reference to best practice forecasting, the AER and/or its consultants ACIL Tasman fail to apply these criteria. Firstly, the adjustments in the draft decision have been made to the modelling output rather than making the adjustments as an input. So rather than incorporate key drivers into the model, the draft decision adjusts the output. This is entirely inconsistent with best practice modelling. An adjustment to the input means that all the factors that go to preparing the forecast have been taken into account as part of the modelling process. Adjusting the output does not consider the full effects of the modelling and is very likely to distort the outcome.

Secondly, unlike the ESC in the 2006-10 review, the AER has missed an opportunity to gain an understanding of NIEIR's modelling capability. In addition, both ACIL and the AER have failed to do any model validation and testing. Had the AER performed validation and testing, it would have been obvious that the forecast of energy volumes provided in the draft decision was not consistent with historical trends. Furthermore, there is no evidence that the AER has attempted to correlate the output with historical results at the aggregate level. Had the AER performed either of tests, the draft decision would have identified that there is an inconsistency between UED's historical energy sales growth of rate of 1.3 per cent and a draft decision of 2.1 per cent. The AER's draft decision acknowledges that customer growth is the lowest of all business but provides for the highest energy rate growth.

UED was not asked to make any adjustment to its modelling prior to the draft decision. UED has considered the adjustments proposed by the AER and provides further comments below.

13.5.2.2 Economic growth

The regulatory process involved in pricing determinations is unavoidably lengthy. UED is firmly of the view that the forecasts presented in the initial Regulatory Proposal in November 2009 were reasonable at that time. However, UED accepts the AER's draft decision view that the forecast could be improved to reflect the current economic outlook.

UED has again engaged NIEIR to prepare a set of revised forecasts taking into account an updated economic outlook. NIEIR incorporates an updated economic outlook by disaggregating the economy into rational components and 'mapping' outputs from integrated modelling components to each of these components in UED's service territory. In addition to components that represent households that align to UED's Residential customers, NIEIR adopts components that represent different industries and industry sectors that can be aligned to UED's commercial and industrial customers. This approach allows NIEIR to reflect growth forecasts for specific sectors of the economy in their modelling in a rigorous and repeatable manner.

The approach adopted by ACIL and accepted by the AER does not replicate this rigorous and repeatable process and is no more likely to produce a robust basis for a reasonable decision than were MMA's efforts in the 2006-10 review process.

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[114] ACIL Tasman, Review of maximum demand forecasts, pp. 2-11; ACIL Tasman, Review of electricity sales and customer number forecasts, pp. 2-4

The revised forecasts undertaken by NIEIR do include this rigorous and repeatable process and the basis for revise proposals in this submission.

13.5.2.3 Air-conditioning penetration

In its draft decision, the AER acknowledges that the use of air-conditioning has a major impact on electricity demand in Victoria. The draft decision also acknowledges that NIEIR's forecast growth rate is lower than historical trends and lower than ACIL's assessment of the air-conditioning penetration rate. NIEIR have provided an updated forecast of air-conditioning sales as part of the revised forecast. This is included in their report and the results incorporated in UED's Revised Regulatory Proposal.

13.5.2.4 Population growth

In UED's view, the AER has made an error in adjusting the forecast to reflect a revised population growth. UED has used a population forecast of 1.2 per cent per annum compared to the AER's preferred growth rate of 1.4 per cent per annum using ABS series B data. All things being equal this would imply an adjustment of energy sales of 0.2 per cent as it relates to population growth.

ACIL sourced ABS data for the basis of a population adjustment. However, the ABS data has been presented by ACIL as if there are only three projections whereas the ABS has produced projections for seventy-two different scenarios. The three scenarios presented by ACIL, as sourced from the ABS, show that the following population projection by 2101:

- Series A – 62.2 million
- Series B – 45 million
- Series C – 35 million.

Series C growth rate of 1.3 per cent most closely reflects the average growth rate in the ten year period ending 30 June 2007.

The ABS data is also based on source data in the 07/08 years, which means the data used is already two years old. That said, in providing a reforecast, NIEIR now concludes that the average forecast population growth rate for Victoria as a whole is closer to series B, with the growth rate for UED's service area being somewhat lower than the average due to the smaller number of connections and fewer growth corridor opportunities in UED's territory than for other businesses.

The method in which the adjustment (accepted by the AER) is made is entirely inconsistent with ACIL's own criteria for best-practice modelling and is prone to a number of inaccuracies. In calculating the adjustment, ACIL has in fact prepared an energy volume forecast:

- based solely on average usage per head of population using historic (i.e. actual) total Residential volumes
- deriving total usage by multiplying this average usage by the ABS population growth rates (which ignores any changes in consumption patterns over time).

- subtracting this total from the businesses total and labelling it an adjustment (when it is not an adjustment but a simplistic and un-tested forecast of the total energy volumes)
- applying the percentage equally over the five years based on UED's share of population. This totally ignores UED lower forecast growth rate of connections and materially overstates UED's energy forecasts.

Contrary to best practice, this approach does not incorporate or even consider the impact of key drivers and their interdependencies, such as change in energy price, changes to energy efficiency over time, weather or impacts of new policy initiatives. ACIL recognises that using simple linear trends based on history is not sufficient for forecasting, yet these key drivers are completely ignored in ACIL's average usage per head figure.

NIEIR's forecasting methodology uses population growth estimates as one of the inputs into detailed construction industry models, which produce new dwelling forecasts. This drives customer number forecasts. NIEIR separates customers into existing and new customers, so that policy impacts can be applied based on how they impact existing customers compared with how they impact new connections.

UED's customer number forecast, that has been accepted by the AER, is the lowest of all Victorian businesses, which is determined by fewer growth corridor opportunities in UED's territory than for other businesses. It is not unreasonable, therefore, to expect that energy volume growth in UED's area to also be lower than other Victorian businesses. As explained earlier, UED's overall share of population and energy will begin to decline, as a proportion of overall energy as the other Victorian businesses' growth outstrips UED's.

ACIL fail to reconcile this by relying on past actual data and a simplistic estimating method. UED's analysis suggests ACIL's estimates underestimate energy volumes by as much as 1,800 GWh (or approximately 3.8 per cent) in the 2001-05 period and overestimate energy volumes by approximately 1,000 GWh (or 2.6 per cent) in the 2006-10 period. This discrepancy is not explained by ACIL but illustrates the sensitivity of this simplistic attempt of modelling an adjustment to the outputs which is really a crude re-forecast of total energy volume based on population growth statistics and ignoring all other inputs.

13.5.2.5 MEPS - lighting

ACIL Tasman say the Commonwealth Government estimated the impact of MEPS based on a more detailed approach than NIEIR's and used "richer, more detailed data". ACIL also go on to say that the impact of the lighting MEPS should be constrained to no more than the impact estimated by the Commonwealth. ACIL imply that NIEIR's assumption that all lamp replacements lead to an eighty per cent efficiency improvement is overstated – the Commonwealth's RIS appendix D allows for a matrix of replacements with smaller efficiency gains.

UED does not have access to the detailed RIS modelling. However, UED does note that selective use of the RIS data can be used to draw totally different conclusions from other independent modelling of the effects of MEPS lighting. For example refer to the following analysis:

The following table is drawn from the RIS tables D.1 and D.3:

Table 13-6: Alternative MEPS – Lighting estimates

Sector	Baseline 2005	After MEPS policy	Change in Australian usage – GWh	Percent contribution to change - %
Residential	5,146	3,472	-1,674	48.8%
Commercial	15,715	14,051	-1,663	48.4%
Industrial and other	7,472	7,277	-96	2.8%
Total	28,233	24,800	3,433	100.0%

As illustrated in Table 13-6, the RIS modelling estimated energy savings split nearly 50:50 between residential and commercial usage. Applying these percentages to the total Victorian MEPS savings by 2016 would be:

- Residential: 353 GWh
- Commercial: 350 GWh
- Other: 21 GWh

These are significantly different results from the ACIL Tasman modelling. Therefore, ACIL Tasman's implication that its table 6 estimates (which are linked to the RIS data) have cast significant doubt on NIEIR's modelling cannot be sustained. ACIL's analysis should be disregarded, given that it is not possible to understand adequately how the RIS modelling was derived.

UED also notes that MEPS applies to a range of technologies, appliances and components listed in Table 13-2 above; and the cumulative estimates of energy savings that underpin the policy decisions to implement the various MEPS schemes is substantially larger than for lighting MEPS alone.

13.5.2.6 CPRS

In accordance with the AER's draft decision UED has updated its forecast to reflect the delay in the implementation of the CPRS scheme. This delay was not known at the time UED prepared its initial Regulatory Proposal.

13.5.2.7 Insulation scheme

The AER considers that the adjustments relating to the insulation scheme should be removed on the basis that the Australian Government announced that the insulation rebate scheme is to be discontinued. The AER has also accepted ACIL's recommendation that the full effect should be excluded from the forecast.

UED concurs with the AER's observation that the scheme has now been discontinued. At the time of making its initial submission the scheme was not cancelled. However UED does not concur that the full effect of the scheme should be removed.

The insulation program began on 1 July 2009 and ended in February 2010. During this eight month period approximately 1.1 million homes were insulated at a cost of $1.5 billion.[115] This is nearly 60 per cent of the ultimate dwelling target of 1.9 million homes cited by ACIL Tasman.

The full impact of the 1.1 million dwellings that have received insulation will not show up in 2009 energy data. Reduced energy consumption, as a result of the scheme, will not show a full effect until 2010 and beyond. Accordingly NIEIR have adjusted for the effect of the full scheme and have made the necessary adjustment to reflect the reduced number of homes insulated.

13.5.2.8 Standby Power

The AER has disregarded the reduction attributed to standby power savings on the basis that ACIL was not aware of Australian policy to introduce mandatory requirements.

The Ministerial Council for Energy (MCE) describes a two stage process as part of a 10 year National Standby Strategy. The first stage allowed voluntary industry action to improve standby performance. A product profile is developed for all key products and voluntary interim targets apply to 2007. If the MCE accepts that voluntary action under stage 1 is shown to be inadequate and regulation is necessary to achieve the standby target, Stage 2 will involve mandatory standby performance measures, applying to 2012.

In addition, mandatory amendments to the energy star rating scheme now requires all manufacturers to take account of standby power when determining appliance Star ratings. While this does not ensure that a uniform 1W target is achieved, it will apply pressure to manufacturers of less efficient appliances and is considered likely to increase the rate of voluntary compliance.

Therefore, reduction attributable to standby power policies is expected in the forthcoming regulatory period. In their modelling, NIEIR has assumed an impact from standby power savings from 2011-12.

13.5.2.9 AMI effect on usage

In its draft decision, the AER has removed the impact of AMI on the forecast reduction in energy usage. The AER's assessment of AMI impacts focuses on price impacts from ToU tariffs and concludes that it is unreasonable to assume any impact arising from AMI in the forthcoming regulatory period, stating:

> *Given the uncertainty surrounding all of the factors that make up AMI and TOU tariff impacts (that is, the Victorian Government's moratorium, the ability to send price signals, potential compensation to customers, the phasing in of TOU and other complexities), the AER considers it reasonable to assume that there will be no material impact on maximum demand and energy consumption over the forthcoming*

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

regulatory control period. Moreover, any impact is likely to arise in the latter years of the period where it cannot be predicted with any reasonable degree of accuracy.[116]

This position transfers 100 per cent of the risk associated with this uncertainty to UED; and is completely at odds with:

- The Victorian Government business case for the AMI roll-out (the fundamental conclusions of which the AER accepted in its decision to approve recovery of substantial costs from consumers); and
- Evidence available in the public domain that confirms consumers will respond to information other than price signals by reducing demand, shifting load and reducing consumption.

UED notes, in particular, that consumer response in the absence of modified price signals is very marked in the water sector where substantial and sustained reductions in total consumption have been effected by a combination of:

- public education (including publication of consumption targets and water supply levels, usage recommendations (such as installation of drip irrigation for gardens), and mandating appliance Star ratings);
- both mandatory and voluntary improvements in water use efficiency of appliances;
- development of new technologies (particularly grey water) and alternative supply (e.g. water tanks); and
- both mandatory and voluntary appliance change-over programs.

UED acknowledges that outcomes in the water sector have been assisted and reinforced by very direct 'public education' through imposition of water use restrictions across much of Victoria and by public announcements of increasing tariff rates. However, evidence shows consumer behaviour was markedly affected prior to imposition of restrictions and is highly resilient in that consumption 'rebound' is occurring at low or negligible levels even where restrictions have been removed.[117]

UED also acknowledges that consumers may have differing perceptions of energy use and water use, but those perceptions are likely to become more closely aligned due to concerns about climate change (and the public education programs that promote the environmental benefits of reduced energy consumption).

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[116] p. 148, *Victorian Draft Distribution Determination–Draft Decision*, AER, June 2010.

[117] For example, information published by the ESC shows total water consumption in Melbourne's three 'retail' water supply areas declined by up to 30% in the decade prior to introduction of Stage 1 water restrictions in August 2006, despite significant increases in population and connections. Water restrictions were increased to Stage 3a over the following 6 months helping to push down total water consumption a further 20% (approximately) in the following 2 years. The ESC has subsequently accepted forecasts that show total consumptions staying flat or rising only slightly over the period to 2014 – even though restrictions are expected to be removed entirely well before then.

Similar trends have occurred in most of the Regional Urban water supply areas, even in those areas that have avoided the extensive restrictions applied in Melbourne.

It is UED's view that it is reasonable to assume that information obtained from the AMI rollout could be conveyed to consumers in a manner that they find useful; that this would reinforce public messages that link energy conservation to reducing climate change impacts; and that consumers will respond by reducing energy consumption (an outcome made 'easier' by the increasing penetration of policy driven energy efficiency measures).

UED is aware that a number of energy utilities across Australia have undertaken trials that examine the impact of AMI (or 'Smart Meters'), alternative tariff structures and various approaches to 'load management'. Brief outlines of these activities are presented regularly at conferences around Australia. However, very little detail of the trials or their results has been published.

UED is also aware that each participant in the Commonwealth's Solar Cities program is required to undertake and report on the results of each of these activities. UED has approached the Commonwealth Department of Climate Change as the agency with responsibility for overseeing the Solar Cities program seeking access to reports on the trials. The Department acknowledged it was receiving these reports but declined to release them in the public domain.

However, there is other information in the public domain that confirms consumers will respond to information they find useful and reduce energy consumption. A particularly useful resource is a report published by the American Council for an Energy Efficient Economy (ACEEE) in June 2010.[118] This report deals entirely with trials undertaken in the residential sector and consolidates information collated from 57 primary studies undertaken over the period of 36 years from 1974, mainly in the USA, Europe and Canada, but also including a small number of trials undertaken in Japan and one trial undertaken in Australia (in 1984).

A particular focus of the report is the type of feedback provided to consumers. That is, the report does not have a narrow economic focus on price signals, but is concerned with all forms of information provided to consumers and the consumers' response to this information. The types of feedback (using classifications developed by EPRI in 2009) are listed as:

- *Standard Billing: An energy bill that displays the monthly kilowatt-hour (kWh) of consumption and the unit rate ($/kWh), the corresponding total cost and other billing charges, as well as the total amount due. This form of feedback generally lacks comparative statistics or any detailed information about the temporal aspects of consumption*

- *Enhanced Billing: Provides more detailed information about energy consumption patterns, and often includes comparative statistics-either comparing the most current monthly electricity usage and expenditures together with historical consumption and/or a comparison to other households.*

- *Estimated Feedback: This approach uses statistical techniques to disaggregate the total energy usage based on a customer's household type, appliance*

[118] *Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities, Report Number E105*, American Council for an Energy-Efficient Economy, June 2010.

information, and billing data. The resulting feedback provides a detailed account of electricity use by major appliances and devices. These most commonly take the form of web-based "home energy audit" tools, offered by a utility to its customers.

- *Daily/Weekly Feedback: These reports use averaged data and often include consumer self-read studies (in which individuals read their meter and record the energy usage themselves) as well as studies in which individuals are provided with daily or weekly consumption reports from the utility or research entity.*
- *Real-Time Feedback-In home energy display devices that provide real-time or near real time energy consumption and energy cost data at the aggregate household level.*
- *Real-Time Plus-In home energy display devices that provide real-time or near real-time energy consumption and energy cost data disaggregated by appliance.*

While many of the studies pre-date AMI, the report pays particular attention to AMI trials, noting that:

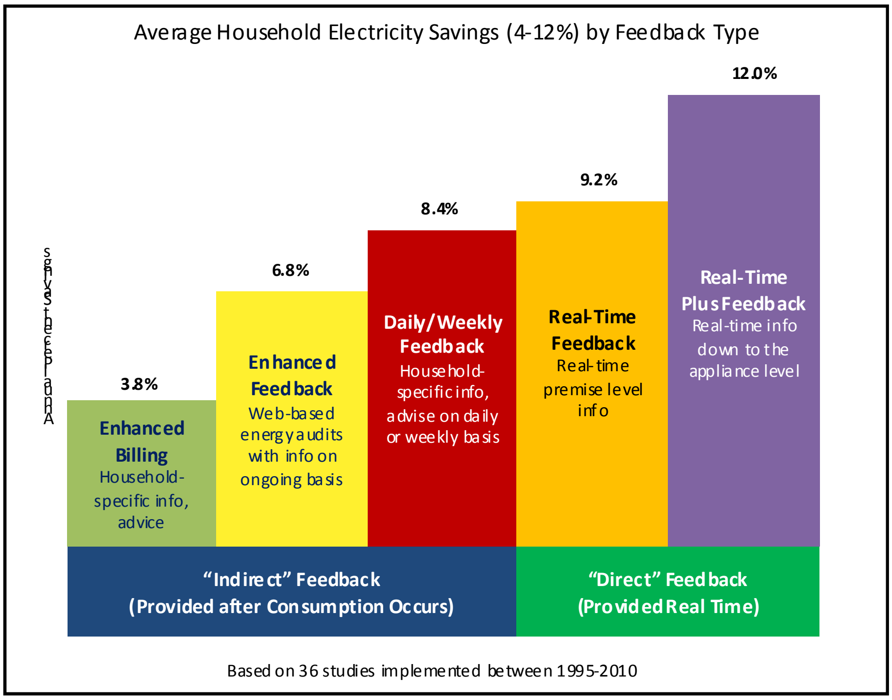
> *Advanced metering is likely to play an important role in meeting the data demands of feedback programs. While feedback can take many forms and need not include utilities or advanced metering initiatives (AMI), the planned proliferation of advanced meters will provide powerful new opportunities for the collection of detailed, household-level energy use data. In combination with a variety of enabling-technologies (e.g., appliance measurement and automation sensors), AM1 could provide households with an expanded array of mechanisms for reducing energy waste and maximizing energy bill savings. Of critical importance, however, is the way in which the feedback is provided and whether people understand the information, believe that they are capable of making a difference, and are motivated to take action. Achieving maximum feedback-related savings will require an approach that combines useful technologies with well-designed programs that successfully inform, engage, empower, and motivate people.*[119]

The report also recognises the importance of climate change as a response stimulant for consumers and identifies 36 studies motivated by this criteria conducted between 1995 and 2009. A significant number of these trials included 'advanced' technology. While noting that outcomes from the trials varied,[120] the report summarised the outcomes from these 36 trials in the diagram below.

[119] p. iv, *Op Cit.*

[120] The ACEE reports notes that energy savings tended to reduce as size of the trial group increased and the trial duration extended; and that the average savings from trials with similar feedback tended to decline with 'epoc'. That is, savings from pre-1995 trials, the majority of which were initiated following the 1970s oil price shocks, were noticeable higher than similar post-1995 trials.

Figure 13-5: Summary of post-1995 energy savings trials (ACEEE)



The report conclusions from considering trials with an AMI component were as summarised below:

> *Advanced meters alone will not achieve energy efficient behaviour change, but with a healthy mix of behavioural science, policy, and enabling-technologies, these technology and networking systems could achieve dramatic energy savings. If utilities begin to recognize the customer as a large resource for demand and cost management, a new utility services paradigm that leaves room for a whole host of new energy management products and services is possible. Now seems to be the time to act to take advantage of the growing public interest in energy and the growing number of products and services available on the market. Notably, however, the electric utility industry as a whole may be moving toward more of a demand-side rather than a purely supply side business perspective in which customer preference will become increasingly important (Galvin Electricity Initiative 2007). Supporting this transition should result in a substantial reduction in energy waste (Galvin Electricity Initiative 2007), which means that the consumer-facing side of the smart grid should be an important consideration in advanced metering deployments[121].*

It is UED's view that this report supports – as reasonable – an assumption that the Victorian AMI rollout would affect energy consumption, particularly if consumers are able to access meaningful information from their AMI meter; and specifically if that information is reinforced

[121] p. 36, *Op Cit.*

by messages that link energy conservation to amelioration of climate change impacts. It is also UED's view that, even without substantial changes in tariff structures, the increasing cost of electricity supply – including the cost of the AMI meter rollout approved by the AER – will tend to reinforce the benefits to consumers of reducing electricity consumption.

13.5.2.10 Concluding comments

In this section, UED has provided revised energy forecasts. These revisions incorporate updates to the following input assumptions compared to modelling undertaken for the initial Regulatory Proposals.

- Updated gross state product forecast to reflect more recent economic conditions
- Replaced population growth forecast inputs with ABS Series B for Victoria
- Amended the CPRS policy assumption to delay the commencement of the CPRS.

The amendments have been made as inputs in the NIEIR modelling framework, not as post modelling adjustments and have therefore incorporated interdependencies between key drivers.

Amendments have also been made to other assumptions, such as air conditioning sales and policy impacts as deemed appropriate based on up to date information. The net effect of all amendments is a 4 per cent increase to total energy sales forecast in the original submission.

The AER correctly states that many of the policies relevant for DNSP energy sales forecasts do not have any historical precedent and therefore there is a high level of uncertainty in respect of their likely impact. UED does not agree, however, that the impact of such policies should be disregarded altogether and the risk associated with uncertainty transferred solely to UED. The policy impacts have been estimated using NIEIR's model, which exhibits elements of good forecasting methodology. However, UED still faces significant downside risks to energy sales over the coming regulatory period due to the uncertainty stemming from these policy impacts.

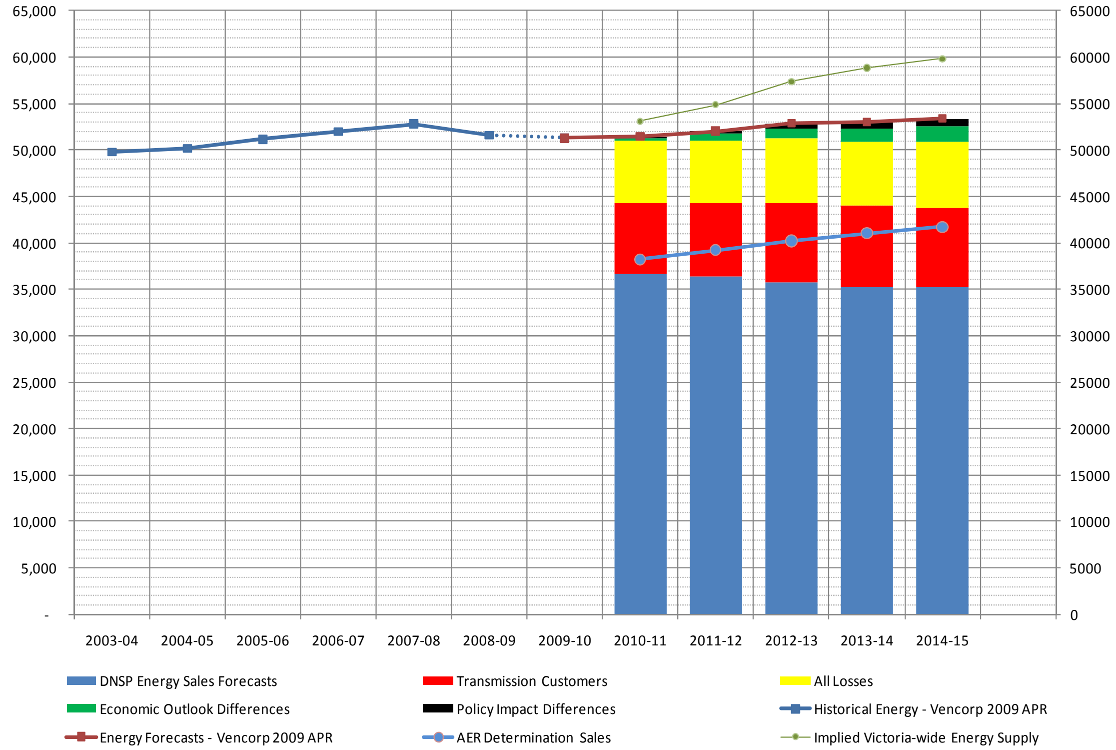
13.5.3 Reconciliation of AEMO/VENCorp 2009 with Distribution Business Forecasts

The AER states that the Victorian DNSPs' forecasts are significantly different from those published in VENCorp's 2009 APR (page 82) and expects the discrepancy is a result of Victorian DNSP overstatement of policy impacts. The comparison is not valid because:

- The VENCorp forecasts include large transmission customers and transmission and distribution losses and therefore cannot be directly compared with DNSP sales forecasts
- The two forecasts were prepared at different times and therefore the economic outlook, particularly Victorian GSP, used by VENCorp was higher than that used by NIEIR for UED's forecasts.

NIEIR has provided a reconciliation of the two forecasts which shows the relative contribution to the discrepancy from these factors, compared with the difference attributable to policy impact.

Figure 13-6: Reconciliation of NIEIR forecasts



The graph also shows that the Victorian energy supply (top green line) implied by the AER's draft determination for sales is not consistent with the VENCorp 2009 forecast.

13.6 UED's revised energy, demand and customer number forecasts

This Chapter describes UED's response to comments made in the AER's draft determination on energy, peak demand and customer number forecasts. UED have further substantiated policy impacts. These policies pose material sales volume risks to UED's business and therefore cannot be disregarded. UED's updated forecasts reflect updated input assumptions, based primarily on new information not available at the time of the original submission.

UED's revised customer number forecast is contained in Table 13-7 below:

Table 13-7: Revised customer number forecasts

	Year Ending 31 December				
Category	2011	2012	2013	2014	2015
Total customer numbers	630,635	636,421	641,506	646,067	650,752

UED's revised energy volume forecasts are shown in Table 13-8 below.

Table 13-8: Revised energy forecasts

	Year Ending 31 December				
Category	2011	2012	2013	2014	2015
Energy (GWh)	7,929	7,936	7,868	7,801	7,800

The tables above indicate that:

- UED's energy sales over the forthcoming regulatory period are forecast to decline at an average rate of 0.4 per cent per annum.
- UED's total customer numbers are expected to grow at an average annual rate of 0.8 per cent.

14. Tariffs

Key messages

UED's original Regulatory Proposal explained that:

- UED will continue to review the effectiveness of its current tariffs and make refinements where these are expected to enhance efficiency.
- In the forthcoming regulatory period, UED will be particularly focused on improving the price signals at peak times, especially in light of the AIMRO meter roll out program.
- UED will also examine initiatives for increasing the participation of the demand side of the market.
- UED also presented its indicative prices for direct control services.

The AER's Draft Decision argued that:

- It does not accept UED's tariff based on the draft decision x factor

In this Revised Regulatory Proposal, UED provides the:

- Revised indicative tariffs based on the x factors contained in this submission

14.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal explained that UED planned to make refinements to existing tariffs during the 2011 - 2015 regulatory period. In particular, UED planned to introduce new tariffs to encourage customers to change their consumption so that there is an overall improvement in asset utilisation and system load factor.

UED also noted that it would engage with stakeholders to identify barriers to efficient use of, and investment in, networks. These consultation groups and the stakeholder consultation processes will be used to facilitate discussion with customers on the implications of tariff reassignment in association with events such as the AIMRO.

UED's original Regulatory Proposal also highlighted a range of initiatives that would be subject to ongoing evaluation, consultation, and if appropriate, implementation over the 2011 - 2015 regulatory period. These initiatives included an increased focus on demand-side participation as a means of delivering more efficient outcomes for network users. The original Regulatory Proposal also provided indicative prices for standard control services, in accordance with the Rules requirements.

14.2 AER's Draft Decision on tariffs

Procedures for assigning or reassigning customers to tariff classes are specified in Appendix G of the Draft Decision. The procedures cover:

- assignment of existing customers to tariff classes at the commencement of the forthcoming regulatory control period;
- assignment of new customers to a tariff class during the forthcoming regulatory control period;
- reassignment of existing customers to another existing or a new tariff class during the forthcoming regulatory control period;
- objections to proposed assignments and reassignments;
- system of assessment and review of the basis on which a customer is charged; and
- installation of interval meters and assignment of customers to time of use (TOU) tariffs.

14.3 UED's response to the AER's Draft Decision on tariffs

The indicative tariffs based on this revised regulatory proposal are provided in the relevant appendix attached to this Revised Regulatory Proposed

The proposed prices for the remaining years of the forthcoming regulatory period are contained in the RIN.

15. CONTROL MECHANISMS

Key messages

UED's original Regulatory Proposal explained that:

- UED supports the AER's proposed form of control for standard control services, subject to the inclusion of an additional factor to recover the costs of the new feed-in tariff.
- UED also supports the retention of the existing tariff re-balancing constraints.
- The Rules should be amended to ensure that DNSPs are able to fully recover all transmission connection and transmission use of system charges.
- For administrative simplicity, the CPI should be applied annually to the approved prices for alternative control services.

The AER's Draft Decision determined that:

- Does not agree with UED's proposal to include an s factor true up mechanism in the price control formula
- It should include a pass through mechanism
- It is not appropriate for the payments made under the PFIT scheme be recovered under clause 6.18.7 of the NER nor that they be recovered through a pass through mechanism
- It is not appropriate that TOUS services, avoided DUOS or inter DNSP charges be recovered under clause 6.18.7 of the NER
- Agrees with UED's proposal to index alternative control services

In this Revised Regulatory Proposal, UED explains that:

- Victorian businesses are not being treated in a consistent manner compared to others states operating in the same market conditions
- The AER tariff formulation is incorrect

15.1

15.2 Side constraints

The AER has accepted UED's formulation in relation to side constraints however the draft decision DD presentation that could be interpreted that rebalancing is required at the component level. This is inconsistent with the NER which requires rebalancing at the class level (s6.18.7).

The Draft Decision section 4.6.2 page 70 states the side constraint (rebalancing) formula "dJt is the proposed price for component j of the tariff class for year t and d j t-1 is the price charged by the DNSP for component j of the tariff class in year t–1. UED believes this criteria is not consistent with the WAPC formula and rebalancing formula should be amended to ensure tariffs moving from one class to another are not constrained.

In order to address this issue and to be consistent with the requirements of the rules UED proposes to introduce the following tariff classes:

- Low voltage small
- Low voltage medium
- Low voltage large
- High voltage large
- Sub – transmission large

These tariff classes are consistant with those used in UED's cost of supply model

The table below provide a mapping of current tariffs to the tariff classes.

Table 15-1:: Mapping of current tariffs to tariff classes

Tariff Code	Tariff Description	Tariff Class
Unmet LVS1R LVS2R LVDed WET2Step TOD	Unmetered Supplies Low voltage small 1 rate Low voltage small 2 rate Dedicated circuit Winter economy tariff Time of Day	Low Voltage Small
LVM1R LVM2R5D LVM2R7D LVkWTOU LVkWTOUH RCACkWTOU TOU	Low voltage medium 1 rate Low voltage medium 2 rate 5 day Low voltage medium 2 rate 7 day Low voltage KW time of use Low voltage KW time of use – HOT Reverse cycle aurconditioning time of use Time of use	Low Voltage Medium
LVL2R LVL1R LVkVATOU LVkVATOUH	Low voltage large 2 rate Low voltage large 1 rate Low voltage large KVA time of use Low voltage large KVA time of use - HOT	Low Voltage Large
HVkVATOU HVkVATOUH	High voltage KVA time of use High voltage KVA time of use - HOT	High Voltage Large
Sub TkVATOU	Subtransmission KVA time of use	Subtransmission Large

*Tariff closed to premises not already taking supply under this tariff and new connections.

15.3 Recovery of transmission charges

As already noted, the AER states that it does not consider it appropriate that transmission connection charges be recovered under clause 6.18.7 of the Rules, and it notes that the Victorian DNSPs have contacted the AEMC to initiate a rule change proposal that would enable the recovery of transmission connection charges under 6.18.7 of the Rules.

There is some possibility that the Rule change will not be in place before DNSPs are required to submit Pricing Proposals (in accordance with Part I of Chapter 6 of the Rules). Therefore, it is appropriate to re-examine the Rules and the National Electricity Law, with a view to determining whether there is course of action open to the AER to provide certainty regarding the recovery by the Victorian distributors of transmission connection charges.

In summary, it appears that transmission connection charges fall within the definition of "direct control services", and therefore the AER's final determination is able to clarify the arrangements by which DNSPs are able to recover these transmission costs. In particular:

- Clause 6.2.5(a) of the Rules provides that:

  A distribution determination is to impose controls over the prices of *direct control services*, the revenue to be derived from *direct control services* or both.

- Chapter 10 of the Rules defines *direct control services* as follows:

  A *distribution service* that is a direct control network service within the meaning of section 2B of the Law.

- Section 2B of the Law provides the following definition:

  A direct control network service is an electricity network service—

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

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

- The Law provides that electricity network service:

  means a service provided by means of, or in connection with, a transmission system or distribution system"

- For completeness, we note that Chapter 10 of the Rules define "distribution system" as follows:

  "A *distribution network,* together with the *connection assets* associated with the *distribution network,* which is connected to another *transmission or distribution system.*

  Connection assets on their own do not constitute a *distribution system.*"

It follows from the above definitions that transmission connection (exit) assets fall within the definition of "distribution system". As such, the AER's determination may relate to the revenue to be earned by the distributor with respect to transmission exit charges, providing that transmission connection (exit) services are classified as *direct control services* for the purposes of the AER's final determination.

The issue regarding the recovery of transmission connection charges arises in the context of the AER's approval of a *Pricing Proposal* which is to be submitted pursuant to clause 6.18.2 of the Rules after the AER publishes its forthcoming distribution determination. The AER is required to assess a Pricing Proposal in accordance with the provisions set out in clause 6.18.8 of the Rules.

Under clause 6.18.8(a), the AER must approve a pricing proposal if the AER is satisfied that the proposal complies with Part I of Chapter 6 and any applicable distribution determination.

Given this requirement, and the observations noted above, the AER could provide certainty of cost recovery of transmission connection (exit) charges by noting in its forthcoming distribution determination that:

- the determination allows for the recovery of transmission connection (exit) costs incurred by a DNSP (as these are direct control services); and
- note that the revenue to be earned in recovering transmission connection (exit) costs are not regulated by the control mechanism set out in the determination; and
- the recovery of transmission connection (exit) charges will be given effect through the AER's annual consideration of each DNSPs' Pricing Proposal, which must provide details of the transmission connection (exit) charges to be recovered by the DNSP including any corrections for any previous under- or over-recoveries.

In the absence of a Rule change clarifying that clause 6.18.7 applies to TUoS and transmission connection (exit) charges, the AER should ensure that the distribution determination includes statements to enable DNSPs to recover transmission exit charges.

It is noteworthy that the AER has previously interpreted and applied clause 6.18.7 in three jurisdictions (NSW, South Australia and Queensland). The AER has evidently applied the Rules in these other jurisdictions in a way that enables the relevant DNSPs to fully recover all transmission charges. Against this background, it is imperative that the AER makes every effort to provide the DNSPs with comfort in relation to this issue.

At this stage of the process UED's preference is for:

- the AER to support the Rule change so that it is passed on time (rule change has been lodged with the AEMC), failing that then
- amend the WAPC formula to include a specific component for the recovery of these charges: failing that then UED proposes to discuss the detail of this formula amendment with the AER and other businesses.
- include a pass through provision with a zero materiality threshold so that it is enabled to be passed through); failing that then

- included as an opex allowance and recovery of building block tariffs (UED has not provide a forecast to the AER at this stage)

15.4 Recovery of other PFIT costs

The Electricity Industry Act (EIA)in Victoria was amended in 2009 to introduce a new Division 5A of Part 2 to place obligations on distributors in relation to premium feed in tariffs. Further 40FH(2) amends the UED distribution licence to include a condition requiring that the distribution company include in a use of system agreement with retailer, a condition that credits to the retailer the amount of $0.60 per kilowatt-hour for qualifying solar energy generation electricity that is conveyed along a distribution system operated by that distribution company during the distributor obligation period.

The Bill introduced in 2009 also amended the National Electricity (Victoria) Act (NEVA) to cover further distribution price determinations beyond the current period, 2006-2010. A new section 16A was introduced to the NEVA to clarify that the Victorian solar feed in credit obligations in the EIA are a regulatory obligation or requirement that relates to the protection of the environment in 2D(1)(b)(iv) of the National Electricity (Victoria) Law (NEL). The NEL, clause 7A states that the revenue and pricing principles include the principles outlined in subclause (2);

> (2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.

The rule change referred to in the earlier section also includes this component. UED is required by law to make this payment, however the law does not afford UED the ability to recover these costs. Again this seems at odds with the AER's objective to ensure the businesses are provided a reasonable opportunity to recover at least the efficient costs the operator incurs. See comments above in relation to transmission connection recovery

15.4.1 Recovery of Inter DNSP costs

The rule change referred to above also includes this component. This will create winners and losers amongst the businesses for what has been common practice since 1994 – true up for inter DNSP costs. See comments above in relation to transmission connection recovery.

15.4.2 Formula errors

On review of the formulas UED believes there are a number of errors and an inconsistency with modelling conventions. Further details are provided below.

Table 15-2: Formula Errors

Pass through	The correct presentation of the pricing formula does not include an explicit pass through term. UED believes this is an oversight and the

	formulation should be structured in the same manner the I factor i.e. (1+ passthrough$_t$) and should be a multiple prior to the brackets not addition or subtraction.
Formula presentation	The price in this formula should be show as a "p" not a "d" to avoid confusion and be consistent with the WAPC pricing control formula. The formula to me modified to ensure tariff assignment within a class that are assigned to another class are not constrained by the rebalancing formula.
WAPC	This formula should be amended to include a double summation for rices rather than a single sum on quantities. This will accommodate the introduction of new tariffs and allow assignment to those new tariffs within the Rules.
Modelling conventions	The AER proposes to round all inputs into the formula to two decimal places before determining the rebalancing constraint. Standard modelling convention is to round the outputs, rather than the inputs. Therefore the AER should allow inputs to be included up to four decimal places and round the outputs so that the model does not bias one way or the other.

16. Service Target Performance Incentive Scheme

Key messages

UED's original Regulatory Proposal explained that:

- UED has set performance targets for the 2011 to 2015 regulatory control period, drawing upon average performance over the past five financial years, modified for factors which are expected to materially affect service levels.
- UED believes that there is currently limited scope to improve reliability across its network.
- A cap of ±5 per cent of revenue on the sum of reliability of supply and customer service components is too high. A cap of ±3 per cent of revenue would better balance the interests of UED and its customers.
- UED supports a major event day exclusion regime based on SAIDI, using a statistical approach for determining exclusions.

The AER's Draft Decision determined that:

- Performance targets for the 2011 to 2015 regulatory control period reflect average performance over the past five financial years, with incentive rates calculated in accordance with the AER's Service Performance Target Incentive Scheme guidelines.
- The MED threshold should be re-calculated annually, drawing upon data from the most recent five-year period.
- The cap on revenue at risk is ±5 per cent, and there is a cap on the revenue at risk of ±0.5 per cent for the telephone answering parameter.

In this Revised Regulatory Proposal, UED explains that:

- UED accepts the 2.5 beta method for setting the major event day boundary. The IEEE standard excludes natural events which are more than 2.5 standard deviations greater than the mean of the log normal distribution of five years of SAIDI data. There is a strong argument that if performance targets are fixed for five years, then the major event day threshold should also be fixed for five years. UED considers that the STPIS should be amended to fix the major event day threshold for five years.
- UED accepts the performance targets calculated by the AER for the reliability of supply measures, unplanned SAIDI, SAIFI and MAIFI.
- UED accepts the performance target calculated by the AER for telephone answering, however it is understood that the target has been evaluated without reference to exclusions under the STPIS regime. UED will provide data to the AER to enable the exempted days to be taken out of the calculation of the call centre performance target.
- UED accepts the overall approach to the calculation of incentive rates, but believes that the AER may have used inaccurate component data. The AER needs to better explain the source of the underlying data.

16.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal explained that the network is becoming increasingly exposed to damaging weather events, including wind storms and temperature extremes. Inevitably, these weather events affect UED's network performance.

UED commissioned independent consultants, AEMCO, to investigate the likely impact of climate change and weather-related events on the company's distribution network over the period from 2011 to 2015. AECOM used data from 2008 as a reference point for assessing the effects of weather-related phenomena on the reliability of electricity supply, and on the performance of the distribution network more generally. Expenditure data from 2008 was also employed as a benchmark when measuring incremental cost effects.

AECOM commissioned empirical work from the CSIRO and drew upon forecasts for the frequency of hot and high wind days from the CSIRO Mk3.5 model. Whilst AECOM estimated that there will be minimal impact on SAIDI as a result of hot days, the impact of wind-related events is expected to increase significantly. AECOM found that the overall impact of high wind days on unplanned SAIDI, net of excluded events, is expected to be eight minutes per annum.

UED's original Regulatory Proposal set performance targets for the 2011 to 2015 regulatory control period, drawing upon average performance over the past five financial years, modified for factors which are expected to materially affect service levels. UED explained that there is limited scope to improve reliability across its network on a sustained and structural basis. Through the operation of an STPIS, seasonal variations in reliability have the potential to cause wide fluctuations in tariffs and revenues from one year to the next.

UED explained that a cap of ±5 per cent of revenue on the sum of reliability of supply and customer service components is too high, as it would expose UED to significant financial risks. Instead, UED proposed a cap of ±3 per cent, which would assist in achieving a better balance between:

- providing an incentive to the company to improve service performance; and
- managing the financial consequences for the company and its customers if service performance is significantly better or worse than the performance targets.

In relation to other design aspects of the service target performance incentive scheme, UED's original Regulatory Proposal:

- supported a major event day exclusion regime based on SAIDI, using a statistical basis for determining exclusions;
- noted the indicative incentive rates for SAIDI and SAIFI will need to be updated after the AER's Final Decision;
- accepted that the AER's incentive rate of -0.04 per cent for the telephone answering parameter for the regulatory control period;
- accepted the AER's view that incentive rates should be fixed for the duration of the regulatory period;
- proposed that public lighting should not be subject to the service target performance incentive scheme; and

- opposed the use of MAIFI as a performance measure, because of the observed trade-off between MAIFI and unplanned SAIFI.

16.2 AER's Draft Decision on the service target performance incentive scheme

Page 693 of Draft Decision states that the AER will apply the SAIDI, SAIFI and MAIFI reliability parameters to the Victorian DNSPs, as set out in the STPIS. For transitional reasons the AER will apply the ESCV's definition of MAIFI.

The STPIS to apply to UED for the forthcoming regulatory period is set out in clause 3.3.3 of the Draft Decision for UED, the salient point of which are summarised below.

In accordance with clause 2.5(a) of the STPIS the cap on revenue at risk is set at ±5 per cent. In accordance with clause 5.2(b) of the STPIS there is a cap on the revenue at risk of ±0.5 per cent for the telephone answering parameter.

For the reliability of supply parameters UED's network will be segmented into urban and short rural feeder types, with targets as set out in table 5 of the AER's Draft Decision for UED (reproduced below).

Table 16-1: AER draft determination performance targets for SAIDI, SAIFI, MAIFI and the telephone answering parameter for United Energy

Feeder	Parameter	United Energy
Urban	SAIDI	55.09
	SAIFI	0.899
	MAIFI	1.074
Rural Short	SAIDI	99.15
	SAIFI	1.742
	MAIFI	2.122
	Telephone answering	58.14 %

Source: AER table 5

The incentive rate to apply to each applicable parameter are calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of the STPIS, and are set out in Table 16-2 of the AER's Draft Decision for UED (reproduced below).

Table 16-2: AER draft determination on incentive rates for SAIDI, SAIFI, MAIFI and the telephone answering parameter for United Energy (per cent per unit)

Feeder	Parameter	United Energy
Urban	SAIDI	0.1432
	SAIFI	8.7494
	MAIFI	0.6999

Rural Short	SAIDI	0.0152
	SAIFI	0.9385
	MAIFI	0.0751
	Telephone answering	-0.040

Source: AER table 6

The major event day threshold is to be set at 2.5 beta from the mean. The major event day threshold is to be calculated in accordance with section 3.3 of the STPIS.

The GSL component of the STPIS will not apply while the ESCV's GSL scheme remains in place. In the event that the ESCV's GSL scheme is withdrawn the AER will implement the GSL scheme in the AER's STPIS.

16.3 UED's response to the AER's Draft Decision on the service target performance incentive scheme

16.3.1 Performance targets: Calculation of the exclusion threshold

UED remains of the view that section 3.3 of the STPIS should be amended so as to provide for the application of a constant major event day threshold which will be calculated and applied for the duration of a regulatory control period.

UED will accept the default parameter value of 2.5 which is multiplied by beta, the standard deviation of the logarithms of the daily SAIDI data. Beta is also known as the log-standard deviation of the data set.

In section 15.7.5 of the Draft Decision, the AER has deliberated on the matter of a constant MED threshold over the forthcoming regulatory control period. The AER has stated that, consistent with Appendix D of the STPIS document, the MED threshold should be re-calculated annually, drawing upon data from the most recent five-year period.

The AER has sought to justify its position by reference to the IEEE standard 1366-2003. Annex B.7 of the standard reports that:

> "From a statistical point of view, the more data used to calculate a threshold, the better. However, the random process producing the data changes over time as the distribution system is expanded and operating procedures are varied. Using too much historical data would suppress the effects of these changes."

Furthermore, the standard notes that:

> "The consensus of the Design Working Group members was that 5 years was the appropriate amount of data to collect. They felt that the distribution system would change enough to invalidate any extra accuracy from more than 5 years of data."

However, the AER has not properly considered these comments, and the associated analysis of probabilities, in the context in which the IEEE standard was developed. In section 4.5 of the IEEE standard, the Institute has noted that:

> "The following process ("Beta Method") is used to identify MEDs. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events."

The requirement to use the last five years' of reliability data is relevant in circumstances in which the performance of the network is being evaluated for the purposes of management review, and there is a need to distinguish between normal, daily operations and major event days. Major event days should be considered separately because they can obscure underlying trends in performance. Importantly, however, the standard makes no reference to performance targets, and the intent behind the definition of MED was not that it should be used in a reliability incentive scheme such as the STPIS.

Hence, when the major event day threshold calculation is being applied in circumstances which differ from those envisaged when the IEEE standard documentation was being prepared, there is a case for departing from some of the details of the calculation method. Various aspects of the technique need to be re-assessed.

The members of the Distribution System Design Working Group may well have reached a different conclusion about the appropriate amount of data to collect, and the use of a rolling five-year time period, if they had been made aware about the ultimate application of the data to the development of performance targets.

The documentation of the IEEE standard does not contain instructions about identifying major event days and then filtering out observations with the objective of creating a database which is then used to determine fixed performance targets. There is a strong consistency argument that if performance targets are fixed for five years, then so too should be the assessed major event day threshold. The Design Working Group members would have given credence to consistency issues if they were appraised of the use of fixed performance targets over the 2011 to 2015 regulatory control period, with the targets having been calculated using data from 2005 to 2009, the same time period over which the MED threshold had been calculated.

16.3.2 Performance targets: AER analysis of the relationship between reliability performance and the MED threshold

The AER has analysed the relationship between performance targets, actual recorded reliability performance, and the size of the MED threshold, using data from Powercor and SP AusNet. Two of the key findings from that work (which is reported on page 648 of the Draft Decision) were that:

- At higher MED thresholds, the SAIDI and SAIFI targets are influenced by a small number of data points; and
- There is greater volatility in the measured reliability performance of distributors when MED thresholds are higher.

Based on its analysis of five years' of historical data, the AER reported that the range of Powercor's and SP AusNet's performance against their targets approximately doubled as the MED threshold was raised from 2.5 beta from the mean to 3.1 and 3.2 beta from the mean respectively. In other words, increasing the beta to the amounts proposed by the distributors would have the effect of potentially doubling the size of the rewards and penalties paid under the performance component of the STPIS. Similar results were observed for Powercor's and SP AusNet's performance against their SAIFI targets.

The AER considered that increases to the MED threshold would result in a greater likelihood of large variations in the S-factor. The AER therefore held that an MED threshold of as high as 3.1 or 3.2 beta from the mean would not adequately serve the objectives of the STPIS, and that consumers would not necessarily receive a commensurate benefit.

The AER nonetheless showed that it was willing to accept some additional revenue volatility and tariff fluctuations in order to provide stronger incentives to distributors to achieve improved supply reliability. The AER considered that setting the MED threshold for both Powercor and SP AusNet at 2.8 beta from the mean would potentially lead to enhanced incentives to improve supply reliability. The AER opined that the cap on revenue at risk would place an upper limit on the volatility of the distributors' revenues, and that the s-bank mechanism could be used to smooth out changes in customer tariffs.

The different facets of the approach taken by the AER to the assessment of the MED threshold appear to be somewhat incompatible:

- On the one hand, the AER is reluctant to accept increases, beyond a small margin, in the size of the parameter which is multiplied by beta, the standard deviation of the logarithms of the data set.

- On the other hand, however, the AER is willing to accept the risk that distributors will be exposed to greater volatility of revenues, and that customers will have to contend with wider fluctuations in prices, both of which may result from the imposition of a requirement that the MED threshold be recalculated from year-to-year. Changes to the threshold will affect the number of days that qualify for exemption in any one year in which reliability performance is being assessed.

As an indication of the potential variation in the exclusion threshold, UED has assessed that the cut-off point, using 2004 to 2008 data, would be 4.15 minutes. The AER has determined that the exclusion threshold assessed from 2005 to 2009 data is 4.75 minutes, and the intent is that this value should apply in 2011, the first year of the forthcoming regulatory period.

Under a regime of an evolving exclusion threshold, there would be less comparability, from one year to the next, between the net results obtained for the reliability measures, unplanned SAIDI, SAIFI and MAIFI. This is because of the change in the effective exclusion trigger in each successive year.

The AER has therefore failed to maintain a consistent approach to its determination of the standards for reliability performance measurement and for the calculation of the major event day exclusion trigger. The fixing of performance targets for a five year period is inconsistent with a rolling five-year average assessment of the exclusion threshold.

16.3.3 Performance targets Conformance to the IEEE standard 1366-2003

As previously noted, the AER has sought to justify its use of a moving five-year average calculation for the MED by reference to annex B.7 of the IEEE standard documentation. The reasoning that the AER has stated is inadequate, firstly because the standard was developed in a different context, meaning that a literal interpretation of its provisions is unwarranted, and, secondly, because the AER has already shown a propensity to deviate from the standard when it appears to be inadequate or incomplete. For instance, the AER modified the procedures for determining the MED in situations in which the reliability data does not possess the right properties, or else does not meet certain criteria.

In the November 2009 release of the STPIS document, the AER amended the techniques to be applied when determining the MED threshold in circumstances in which the logarithms of the daily unplanned SAIDI data are not normally distributed. The AER therefore introduced greater flexibility into the MED calculation. The IEEE standard did not appear to countenance the possibility that the SAIDI data for some distribution networks might not be log-normally distributed. The standard simply assumes that daily SAIDI data is log-normally distributed (refer to paragraph B.4.3 on page 30). In a comparable fashion, the IEEE standard has not considered an appropriate treatment for the MED threshold when the particular transition point has been used as an input to the determination of performance targets under a service target performance incentive scheme. Accordingly, the AER should apply logic and intuition and not be bound by the precise wording of the standard. A constant and uniform exclusion threshold aligns better with performance targets that have been pre-determined.

16.3.4 Formulation of performance targets

UED accepts the performance targets calculated by the AER for the reliability of supply measures, unplanned SAIDI, SAIFI and MAIFI. The performance targets are presented in Table 15.17 of the draft decision, and are also incorporated in a separate workbook prepared for, and sent to UED.

However, UED does object to the manner in which the AER has distorted the monthly figures for planned customer minutes off-supply, which were included in the workbook provided to the AER. The annual total for planned SAIDI in 2009 was 15,429,025 minutes, a figure obtained by summing the monthly readings. The same figure can be sourced from the planned minutes off-supply column in the annual reliability report for 2009, which has been submitted to the AER. Although planned SAIDI is not a component of the AER STPIS, UED considers that the numbers still need to be monitored, and that the AER should not arbitrarily amend the data.

The AER also changed aggregate customer numbers across the network from 610,225 to 609,585 (for 2005), and from 616,358 to 616,390 (for 2006). No reason for the variation was given, and UED believes that the change was unwarranted. UED notes that the rural and urban breakdown of customer numbers was not amended to match the new totals, with the result that the calculation of performance data across rural and urban parts of the network was unaffected. The correct rural and urban customer numbers were therefore used, and the computed values of unplanned SAIDI, SAIFI and MAIFI are valid. These values were used to determine performance targets under the STPIS.

16.3.5 Cap on revenue at risk

As already noted, UED explained that a cap of ±5 per cent of revenue on the sum of reliability of supply and customer service components is too high, as it would expose UED to significant financial risks. Instead, UED proposed that a cap of ±3 per cent would better balance the interests of UED and its customers.

Under the Draft Decision the cap on revenue at risk will be set at ±5 per cent, while there is a cap on the revenue at risk of ±0.5 per cent for the telephone answering parameter.

UED will apply the 5 per cent cap on revenue at risk, but does not accept the AER's argument that a lower, 3 per cent cap would give rise to a material lessening of the incentives of the scheme. UED does not consider that a lower cap would dampen the incentives, or somehow diminish the business case for improvements in network reliability.

16.3.6 Mechanics of the scheme: Incentive rates

The AER has applied the method of calculating incentive rates which is set out in sections 3.2.2 and 5.3.2 of the STPIS. UED accepts the overall approach to the calculation of incentive rates, but has doubts about the validity of the underlying data which has been used by the AER.

UED notes that the AER has not explained the source of much of the component data which has been employed in the evaluation. In particular, the AER has not documented:

- The source of the average annual energy consumption data, measured in megawatt hours (MWh), and shown separately for urban feeders and for short-rural feeders.

- The forecast inflation rate for calendar year 2010 which has been used to escalate the Value of Customer Reliability (VCR).

UED notes that the VCR published by CRA International in August 2008 was $47.85/kWh in current prices. Clause 3.2.2(b) of the amended STPIS document states that the VCR will be adjusted for CPI from the September quarter 2008 to the start of the relevant regulatory control period. In a September 2009 explanatory statement outlining proposed amendments to the STPIS, the AER also stated that the CPI used to escalate the VCR to the start of the regulatory control period would be the CPI used to roll forward a distributor's asset base in the roll forward model. However, in the Draft Decision for Victoria, it is unclear whether the AER has applied consistent inflation rates.

In the draft decision financial model released for UED, the AER has also made a mistake in terms of the use of the VCR for the urban SAIDI incentive rate calculation. The VCR applied was $52,000, whereas in all other calculations, the AER has adopted a VCR of $50,298.

The incentive rates will need to be recalculated for the AER's final determination.

16.3.7 Mechanics of the scheme: Telephone answering parameter

UED gratefully acknowledges the clarification that the AER has provided to the definition of call centre performance. According to the draft decision (page 662), the telephone answering parameter is to be calculated as follows:

> (Calls to the fault line forwarded to an operator *less* calls abandoned within 30 seconds of the call being queued for response by a human operator, *less* calls to the fault line not answered within 30 seconds)
>
> Divided by:
>
> (Calls to the fault line forwarded to an operator, *less* calls abandoned within 30 seconds of the call being queued for response by a human operator).

UED notes that none of the Victorian distributors was able to correctly foreshadow the call centre parameter calculation method proposed by the AER. The AER has criticised the distributors by referring to their confusion and misinterpretation. In response, UED points out that such confusion would not have arisen if the AER had provided a formal definition of the telephone answering measure in the STPIS document. UED also believes that it was somewhat remiss of the AER to not provide a worked example in a spreadsheet. UED considers that, at the very least, the AER could have provided the appropriate information about terminology and calculation approaches while it engaged in email correspondence with the distributors. Revised call centre data for the full 2009 calendar year was supplied to the AER in March 2010.

The source of confusion is essentially the incompleteness of the STPIS paper. The limited information that is contained within the STPIS document is borrowed and paraphrased from the ESCV Information Specification (Service Performance) guideline. In the STPIS document, the telephone answering parameter is defined as follows:

> "Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to:
>
> - calls to payment lines and automated interactive services;
> - calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned.
>
> Note: Being placed in an automated queuing system does not constitute a response."

There are very few differences between the STPIS definition of telephone answering, and the ESCV definition of "calls to fault line not answered within 30 seconds". The differences are shown below with the appropriate words underlined:

> **"The total number of** calls to the fault line **not** answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller

speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to:

- calls to payment lines and automated interactive services;
- calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned.

Note: Being placed in an automated queuing system does not constitute a response."

The adoption of ESCV style wording suggested to UED that the AER wished to mimic the ESCV approach, with only minor modifications to the interpretation of the final call centre parameter. In particular, there is nothing in the ESCV terminology which states explicitly that:

- The appropriate constituent variable to use is not the total number of calls to the call centre fault line, but calls to the fault line forwarded to an operator; and that
- The variable, "calls abandoned within 30 seconds of the call being queued for response by a human operator" should appear in both the numerator and the denominator of the relevant expression.

Accordingly, UED maintains its position that the AER should make appropriate amendments to the STPIS paper.

The initial ambiguities having now been resolved, UED is satisfied with the proposed approach to working out the telephone answering parameter. UED accepts the results of the calculations undertaken by the AER, which were presented in a separate spreadsheet workbook released with the Draft Decision. Provisionally, the target performance, over the 2011 to 2015 period, for calls answered within 30 seconds, will be 58.14 per cent.

UED understands that the telephone answering target has been evaluated without reference to exclusions under the STPIS regime. Under the STPIS, the values of variables on excluded days should not be incorporated into the overall annual assessment of call centre performance. UED will therefore provide daily data to the AER so as to enable the exempted days to be taken out of the calculation of the annual performance results. Removal of the exempted days will have an impact on the performance outcomes obtained. An average of the net performance results over the period from 2006 to 2009 will then be used to determine the call centre performance target.

16.3.8 Guaranteed service level payments

UED is aware that the AER has written to the Essential Services Commission of Victoria (ESCV) with a request that the ESCV should amend the Victorian Electricity Distribution Code (EDC) so as to allow for the implementation, within Victoria, of the national GSL payments scheme. The AER has in mind that the national GSL scheme should be applied over the 2011 to 2015 regulatory period. The Victorian Department of Primary Industries (DPI) has reportedly advised the AER of its expectation that the AER will derive projections, for the forthcoming regulatory period, of the volume and value of GSL payments to electricity customers.

The forecasts of GSL payments prepared by the AER and published in the draft determination have been made in the context of the Victorian GSL scheme. UED had provided forecasts of GSL payment volumes and values under the ESCV scheme because it was requested to do so by the AER in correspondence dated 5th February 2010. UED did not adjust the unit rates for the payment categories because the rates are fixed in the Electricity Distribution Code and in the Public Lighting Code (PLC). Accordingly, the amount of the payment for each particular type of service breach was not indexed for inflation.

The AER examined the projections submitted by UED, and then undertook revisions. The forecast payment volumes were worked out by taking an average of the recorded number of payments over the five-year period from 2005 to 2009. In some cases, the average calculation was performed using data from 2006 to 2009 only.

UED has reviewed the spreadsheet workbook of GSL payments which was released by the AER with the Draft Decision. In general, UED does not object to the forecasts which have been published in Table 15.23 (AER conclusion on GSL payments for United Energy, $ nominal) of the Draft Decision. However, UED is aware that the AER has used inconsistent sets of data when formulating projections of the volume of late new connections.

Over the four year interval from January 2004 to September 2008, UED made GSL payments for late re-connections, as well as for delayed new connections. However, in the period since September 2008, UED has restricted the GSL payment obligation to instances of new connections which are not done within the standard connection timeframe.

UED supplied the AER with two sets of data. From 2004 to 2008, the numbers are comprised of payments made in respect of both new connections and late re-energisation connections. However, for 2009, the GSL payments series are restricted to new connections (and new installations). The historical data from 2004 to 2008 has also been revised to separate out the late re-energisation (or "move-in, move-out") connections.

The AER has used the reported series for the sum of new connections and re-energisation connections from 2004 to 2008, but has then inappropriately added in the 2009 results for new connections only. The basis for the 2009 data clearly differs from the basis of the earlier data, and the AER has made no attempt to properly "splice" the old data onto the new. Accordingly the AER forecasts of GSL payments for late connections, which are computed as an average of the recorded observations from 2005 to 2009, are invalid and should not be used without amendment.

Table 16-3: UED assessment of the AER draft decision on GSL payments

GSL variable	Forecast number	Forecast payments	UED assessment
Number of payments made for arriving more than 15 minutes late for an appointment	30	$592	Accepted
Connections not made on the agreed date, with a delay of 1-4 days	64	$4,874	Not accepted. The AER has mixed historical data from two inconsistent series.
Connections not made on the agreed date, with a delay of 5 or more days	10	$2,360	Not accepted. The AER has mixed historical data from two inconsistent series.
Total number of connections not made on an agreed date	72	$7,234	Not accepted. The AER has mixed historical data from two inconsistent series.
Number of customers experiencing more than 20 hours of sustained interruptions in a year	2,071	$207,075	Accepted.
Number of customers experiencing more than 30 hours of sustained interruptions in a year	237	$35,475	Accepted.
Number of customers experiencing more than 60 hours of sustained interruptions in a year	34	$10,200	Accepted.
Number of customers experiencing more than 10 sustained interruption events in a year	61	$6,050	Accepted.
Number of customers experiencing more than 15 sustained interruption events in a year	0	__	Accepted.
Number of customers experiencing more than 30 sustained interruption events in a year	0	__	Accepted.
Number of customers experiencing more than 24 momentary interruptions in a year	0	__	Accepted.
Number of customers experiencing more than 36 momentary interruptions in a year	0	__	Accepted.
Number of faulty street lights not repaired within two business days of the distributor being notified	18	180	Accepted, rounded down to nearest integer.
Aggregate value of GSL payments		**$262,072**	

Source: UED assessment of AER draft decision on GSL payments (AER Table 15.23).

UED had previously prepared projections of GSL payments in the electricity connections category by calculating an average of the observed data from 2004 to 2009. UED maintains that this is still the best means of assembling the forecasts. However, as an alternative, UED has also modified its projections by averaging the recorded data from 2005 to 2009. The stated time period is that which has been adopted by the AER for averaging purposes. The following are the results obtained:

- Number of connections (in new installations, rather than existing premises) not made on the agreed date, with a delay of 1-4 days = 6. The value of such payments is $750.

- Number of connections (in new installations) not made on the agreed date, with a delay of five or more days = 7. The value of such payments is $1,750.

There is also a need to amend the forecast of the total GSL payments which are incorporated as a line item in the operating expenditure allowance. UED has assessed that an appropriate operating spending allowance is $262,072 per annum. This amount is less than the estimate of $266,810 put forward by the AER, in its draft decision, because of the aforementioned anomalies in the AER's projections of GSL payments for late electricity connections.

16.3.9 Transition to a national GSL scheme

In the event that the Victorian GSL scheme is superseded by a national GSL scheme, then the applicable payment categories will be those listed in Appendix A of the STPIS document. UED considers that the AER should maintain the same trigger points for particular payments as are currently in place under the Victorian scheme. Furthermore, UED notes that:

- There will be no requirement on distributors to make GSL payments for momentary interruptions above certain thresholds. Momentary interruptions are not a feature of the national regime.

- Distributors will be liable for an additional GSL payment in respect of the duration of any one unplanned interruption experienced by a customer in a regulatory year. The applicable threshold for the duration of a single interruption GSL payment will be 12 hours, and the unit rate per payment has been set at $80.

- Another category to be introduced will be a payment for failing to notify customers of planned service interruptions. The amount of each payment has been predetermined at $50.

17. Efficiency Benefit Sharing Scheme

Key messages

UED's original Regulatory Proposal explained that:

- UED's operating expenditure forecasts already reflect substantial efficiency gains, and therefore the company should not be penalised in the event that it cannot achieve these savings.
- UED has proposed four categories of uncontrollable costs that should be excluded from the operation of the Efficiency Benefits Sharing Scheme (EBSS). In addition, UED has proposed that the costs of non-network alternatives and pass-through events should also be excluded from the scheme.

The AER's Draft Decision determined that:

- The efficiency carryover mechanism (ECM) that applies during the 2006-10 regulatory period should be merged with the EBSS. This in effect, requires the AER to apply the EBSS retrospectively to 2009 and 2010.
- If an event occurs that might ordinarily be deemed a pass-through, but which has cost impacts that are insufficient to meet the materiality threshold, then no exemption from the EBSS will be granted.
- The AER will adopt a method for adjusting EBSS quantities to reflect demand growth which differs from the method adopted by the ESCV for the same purpose.

In this Revised Regulatory Proposal, UED explains that:

- The operating and maintenance expenditure efficiency carryover amounts from 2006 to 2010 should be incorporated into the building block revenue requirement for the 2011 to 2015 regulatory period, without merging the ECM and EBSS.
- The EBSS should start anew in 2011, with the first year formula (as shown on page 600 of the Draft Decision) taking effect. The final year formula (shown on page 600 of the Draft Decision) should not be applied in 2011.
- UED maintains that there are sound reasons to remove from the EBSS the costs of events which qualify as pass-throughs but do not satisfy materiality considerations.
- UED considers that the demand growth adjustment should be consistent with that used under the efficiency carryover mechanism developed by the ESCV.

17.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal noted that section 2.3.2 of the EBSS Guidelines states that:

> " The AER will permit a DNSP to propose a range of additional cost categories for exclusion from the operation of the EBSS. These categories must be specific to the business, and the DNSP must provide an identifiable reason for exclusion, and should not involve an ongoing business activity. A DNSP must propose cost categories for exclusion from the EBSS in their regulatory proposal prior to the commencement of the regulatory control period during which the EBSS will be applied."

In light of the above requirements, UED proposes that the following cost categories should be classified as uncontrollable for the purposes of the EBSS:

- debt and equity raising costs;
- self-insurance costs;
- insurance costs; and
- expenditure that meets all of the necessary requirements for an approved pass-through event other than satisfying the materiality threshold.

UED's original Regulatory Proposal noted that an efficiency gain is defined in the EBSS as a reduction in operating expenditure in any one year relative to forecast. UED argued that to ensure that the operation of the EBSS is consistent with the concept of 'fair sharing', which is embedded in the Rules, UED believes it would be inappropriate if the company were to be penalised for failing to deliver the ambitious profile of cost savings that is reflected in its operating expenditure forecasts. In particular, the ordinary operation of the EBSS would expose UED to penalty payments if it achieved the cost savings more slowly than expected. Such an outcome would be inconsistent with the concept of fair sharing.

To address the potential anomaly described above, UED proposed two remedies:

- For the purposes of the EBSS, UED's forecast operating expenditure should be profiled to reflect the average of the forecast over the 5 year period. Therefore, the forecast operating expenditure for the purposes of the EBSS should be $120.4 million (in 2010 dollars) for each year in the forthcoming regulatory period; and
- If UED's total operating expenditure over the forthcoming regulatory period does not exceed the forecast of $601.8 million, then no EBSS penalties should apply.

UED noted that its proposed approach would ensure that the concept of 'fair sharing' efficiency gains is properly reflected in the operation of the EBSS. UED also proposed the adoption of the ESC's growth adjustment formulae. A full description of UED's proposed growth adjustment was provided in appendix H-5 of the original Regulatory Proposal.

UED's original Regulatory Proposal supported the AER's view that sanctioned increases or decreases in actual operating expenditure directly attributable to pass-through events should not be incorporated into the calculations underpinning the EBSS. However, UED also explained that the materiality threshold should not apply to the exclusion of pass through costs, as these costs are, by definition, beyond the company's control. UED's proposed pass-through events were presented in Chapter 18.3.1.1 of the original Regulatory Proposal.

17.2 AER's Draft Decision on the efficiency benefit sharing scheme

17.2.1 Merging of ESCV efficiency carryover mechanism with the EBSS

As expected, the AER will apply the Efficiency Benefits Sharing Scheme (EBSS) over the 2011 to 2015 regulatory period. However, the AER has also sought to merge the efficiency carryover mechanism (ECM) that applies during the 2006-10 regulatory period with the EBSS, (as described on page 600 of the Draft Decision):

> "Given that the Victorian DNSPs have been operating under an efficiency carryover mechanism that is substantially similar to the AER's efficiency benefit sharing scheme, the AER will use this formula to calculate efficiency gains or losses under the EBSS for 2011, rather than the first year formula above."

The AER would like to roll forward the ECM, merging it seamlessly with the EBSS, by calculating an efficiency gain or loss for year 6 (meaning 2011) which is affected not just by a comparison of forecast and actual performance in year 6, but also by the assessed efficiency gain (or loss) for years 4 and 5 respectively.

The **first year formula** is shown as:

$$E_1 = F_1 - A_1$$

Where:

$E_1 =$ The efficiency gain or loss in year 1.

$A_1 =$ Actual operating expenditure incurred by the DNSP for year 1 of the regulatory control period.

$F_1 =$ Forecast operating expenditure accepted or substituted by the AER in the distribution determination for year 1 of the regulatory control period.

The **final year formula**, to which the AER is referring in its statement (via the demonstrative pronoun "this"), is set out as:

$$E_6 = (F_6 - A_6) - (F_5 - A_5) + (F_4 - A_4)$$

The final year formula is actually supposed to be invoked in 2016, the first year of the 2016 to 2020 regulatory control period, however the AER is also proposing to use the formula in the first year of the forthcoming regulatory period, 2011.

17.2.2 Excluded cost categories

The AER has accepted that certain categories of uncontrollable cost should be exempt from consideration under the EBSS. The categories of forecast operating expenditure which have been excluded are:

- Debt and equity raising costs.

- Self-insurance costs.
- Superannuation costs for defined benefits and retirement schemes.
- The DMIA; and
- GSL payments.

Certain other types of exempt cost were mentioned in the AER's EBSS paper, and these are:

- Expenditure on non-network alternatives; and
- Approved increases or decreases in actual operating spending associated with recognised pass through events.

However, the AER has not approved two cost categories proposed by UED, notably insurance expenditure, and the costs of events that would ordinarily qualify for pass-through status, other than that the materiality threshold has not been satisfied.

The AER has acknowledged that insurance costs have been exempted from the EBSS in previous distribution determinations. The reason for the exclusion, according to the AER, is that projections of insurance expenditure have previously been derived by expert analysis, with the forecasts having been de-linked from historical costs. However, for the Victorian Draft Decision, the AER has determined an insurance operating expenditure allowance by drawing upon actual spending in 2009. Consequently, reported spending on insurance has been used to set costs going forward, and the AER believes that insurance costs should be incorporated into the overall pool of costs that is subject to the EBSS.

UED proposed that if an event occurred which did not meet the materiality threshold, but would otherwise have been accorded pass-through status, then the costs associated with that event should be excluded from the EBSS formulation. However, the AER has replied that pass-through events must be designated as such if their costs are to be excluded from the operation of the EBSS.

17.2.3 Demand growth adjustment

UED proposed that the EBSS should be subject to the same form of demand growth adjustment as the ECM. However, the AER rejected this proposition and has devised an alternative method which has not been documented properly and is not represented in the financial model supplied.

17.3 UED's response to the AER's Draft Decision on the efficiency benefit sharing incentive scheme

17.3.1 Framework and Approach Paper and the EBSS

In order to make use of the final year formula in 2011, the AER would, in effect, need to apply the Efficiency Benefits Sharing Scheme retrospectively to 2009 and 2010. In its

EBSS explanatory paper, released in June 2008, the AER did not signal an intent to apply the EBSS in a backward looking manner to a previous regulatory control period.

The discussion in the AER's final decision for the EBSS conveys no sense that the EBSS should be used for regulatory periods prior to the one in which it first takes effect. In fact, there are concluding comments in the final decision document which seem to give more weight to the treatment of carry-overs from pre-existing incentive based mechanisms. From page 13 of the final EBSS decision:

> "The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place."

There is no suggestion, in either the final decision for the EBSS, or the EBSS explanatory paper that the EBSS will be used in the final year of the previous jurisdictional scheme.

The Framework and Approach paper for Victorian electricity distributors gave no indication that the AER planned to link the ECM to the EBSS. The Framework and Approach paper simply mentioned the calculation of annual carry-over amounts under the efficiency carryover mechanism of the ESCV, and the addition of these amounts to the building blocks for 2011 to 2015. The following is the relevant excerpt (from page 112):

> "For efficiency gains/losses realised in the current 2006-2010 regulatory control period, each annual carryover amount under the efficiency carryover mechanism will be calculated and used in the building block determination for the next regulatory control period, 2011-2015. The AER will incorporate all carryover amounts accrued in any year of the current regulatory period into forecast opex amounts for the next regulatory control period."

The commentary in the Framework and Approach paper seems to be consistent with the original intent of the ESCV scheme. The ESCV discussed the application of the efficiency carryover mechanism to the 2006 to 2010 regulatory period, in its EDPR final decision for the 2006 to 2010 period. The treatment of future carryover amounts was mentioned (on page 431), with the ESCV signalling its view that carryover values should be included in the revenue determination for the 2011 to 2015 regulatory period:

> "On this basis, the efficiency carryover amounts for operating and maintenance expenditure to be included in the 2011 revenue requirements and arising from efficiency gains achieved in the 2006-10 regulatory period will be calculated as follows:
>
> - An efficiency gain (or loss) in operating and maintenance expenditure in any year during the 2006-10 regulatory period is to be calculated as the reduction (or increase) in the level of recurrent operating and maintenance expenditure compared to the forecast for that year. Recurrent in this sense is taken as the underspend (overspend) between forecast and actual in year one, then the incremental underspend (overspend) in subsequent years."

The ESCV further stated that:

> "In so far as the carryover amounts for operating and maintenance expenditure arising from the 2006-10 regulatory period and to be applied in the 2011 regulatory period are concerned, the presumption will be that, where a negative carryover amount arises, it

will be applied in calculating the building blocks revenue requirement for the 2011 period."

In its final decision, the ESCV did not explicitly address how it proposed to deal with the incremental under-spend or over-spend for 2010. The incremental under-spend (or over-spend) cannot be calculated in advance because the efficiency gain (or loss) will not be known at the time of the final determination for the 2011 to 2015 regulatory period. The efficiency gain (or loss) cannot be worked out because actual O&M spending for 2010 will not be known until early in 2011. Therefore, the efficiency gain for 2010 should be set at zero.

The AER has released a final model which shows the carry-over amounts accrued under the ESCV efficiency carryover mechanism, however this model has been inappropriately labelled as the draft decision for the EBSS. The model is nonetheless correct in showing that the O&M incremental gain for 2010 is $0.0 million (measured in real terms, $2010). The zero assessment of the incremental gain comes about because the O&M under-spend in 2010 is presumed to be equal, in real terms, to the O&M under-spend in 2009.

UED believes that neither the Framework and Approach paper, nor the EBSS explanatory document authorises the AER to effectively join together the ECM and the EBSS.

There are also sound practical reasons for maintaining the separation between the two schemes, notably that:

- The categories of excluded cost differ as between the ECM and the EBSS; and
- The AER is proposing to use a different method of adjusting for demand growth under the EBSS as compared to the method employed under the ECM.

Owing to these scheme differences, the forecast and actual cost figures employed in calculations under the EBSS will not be strictly comparable to the benchmark and outturn costs used in ECM calculations. Therefore, the data on costs used for the purpose of the ECM cannot logically be added to, or subtracted from, the forecast and actual costs from the first year of the EBSS.

Instead, the operating and maintenance expenditure efficiency carryover amounts from 2006 to 2010 should be incorporated into the building block revenue requirement for the 2011 to 2015 regulatory period.

The EBSS should start anew in 2011, with the first year formula taking effect. The final year formula (shown on page 600 of the AER Draft Decision) should not be applied in 2011.

17.3.2 UED position on excluded cost categories

UED understands that the AER has classified insurance spending as normal operating expenditure, with the implication that this category of expenditure will not be exempt from the EBSS. The AER has accepted figures presented by UED showing a $0.7 million step-change in insurance costs which took effect from September 2009 (page 193, Appendix L of the Draft Decision).

The AER has affirmed that, in accordance with section 2.3.2 of the EBSS, approved increases or decreases in actual operating spending associated with recognised pass-through events will be treated separately from the actual expenditure amounts used to calculate carry-over gains or losses under the EBSS. However, the AER has also held that if an event occurs, that might ordinarily be deemed a pass-through, but which has cost impacts that are insufficient to meet the materiality threshold, then no exemption from the EBSS will be granted. The rationale advanced by the AER for to support its position is somewhat curious and is presented below in full context:

> "The AER notes that United Energy also proposed that if an event occurs that does not meet the materiality threshold, but would otherwise be determined to be a pass through event, then the costs associated with the event should be excluded from the EBSS. However, under the EBSS, only the costs of recognised pass through events are excluded from the EBSS. The AER notes that by excluding such amounts from the EBSS, DNSPs would have an incentive to only inform the AER of events that result in higher EBSS carryover amounts. However, clause 6.5.8(c)(3) of the NER requires that in implementing the EBSS the AER must have regard to the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses. Consequently the AER considers that the cost associated with events that occur that do not meet the materiality threshold, but otherwise would have been determined to be pass through events, should be included in the EBSS."

The AER's logic is curious and unsubstantiated. The AER is concerned about the flow of information from distributors to the regulator, and seems to suggest that the flow will improve if distributors are not permitted to quarantine from the EBSS, the costs of incidents which fall below the materiality threshold. The AER's contention that distributors will only selectively pass on details about adverse happenings, depending upon the perceived impact on carryover amounts is inaccurate and unsubstantiated. Distributors have a strong incentive to inform the AER about unfavourable incidents because the businesses will generally want to apply for pass-through status. There is no certainty of a pass-through application being approved, but distributors will lodge applications if the values being sought are reasonably close to the materiality threshold.

The carryover component of the EBSS, which is equal to the incremental gain, is affected by the forecast underspend (or overspend) in the current year, as well as by the reported underspend (or overspend) in the previous year. Distributors are unlikely to have the relevant data to hand at the time at which a pass-through application is being submitted. This is because actual operating and maintenance costs, a key component of the EBSS formulation, are only known and reported on an *ex post* basis.

The EBSS and its predecessor scheme, the efficiency carryover mechanism, provide useful incentives for businesses to control costs. However, the schemes cannot influence an *ex ante* decision about whether or not to submit an application to have an event classified as a pass-through.

If the AER maintains its decision to disallow the removal, from the EBSS, of the costs of near pass-through events (that is, incidents which qualify as pass-throughs but do not satisfy materiality considerations), then distribution businesses will be unfairly and unreasonably penalised. The AER should therefore adopt the position put by UED on this matter.

17.3.3 UED standpoint on demand growth adjustments

UED considers that the demand growth adjustment should be consistent with that used under the efficiency carryover mechanism developed by the ESCV. The ECM method has a firm foundation in partial factor productivity measures. The AER has not reviewed or considered the substantive arguments raised by UED on the EBSS in Appendix H5 of UED's original Regulatory Proposal. The AER has provided no comments on the partial factor productivity submission by UED, and so this information will be provided once again as an attachment to this revised regulatory proposal.

The method of demand growth adjustment which was applied by the ESCV over the 2006 to 2010 regulatory period is supported by economic theory and is underpinned by empirical research undertaken by the Pacific Economics Group.

In contrast, the approach taken by the AER to adjust the operating cost benchmarks in response to variations in the drivers of demand growth is entirely nascent and *ad hoc*. There is no documentation or explanation other than a couple of paragraphs in the Draft Decision, and table J6 in the appendix to the Draft Decision. The model of the EBSS released with the Draft Decision contains no further information, and, in fact, simply replicates the functioning of the ECM over the 2006 to 2010 period. In short, the AER has done no empirical work in relation to this matter.

Appendix H5 of UED's original Regulatory Proposal contains information about the ESCV demand growth method which was not reported in Volume I of the ESCV's Final Decision. This information has been gleaned through private correspondence between UED and Mark Lowry of the Pacific Economics Group, and by a thorough review of PEG's 2004 report, *Predicting Growth in SPI's O&M Expenses.* To assist the AER, the following summary is provided:

- The Pacific Economics Group compiled an index of growth in the productivity of O&M inputs which was based upon the following formulation: [PFP index] = [An elasticity weighted output quantity index] – [An index of growth in the input quantity index].

- The PFP index is the index of growth in the productivity of O&M inputs and can be used to formulate output growth projections.

- In order to derive an elasticity-weighted quantity index, a transcendental logarithmic (translog) function was used to estimate the elasticity of costs with respect to output for the individual output variables. The cost function is represented by equation (22) in PEG's 2004 report. The econometric analysis made use of data from 72 companies.

- The output related cost elasticities from single output variable versions of the translog function were normalised to give 0.43136 (for customer numbers), 0.29627 (for delivered energy volumes), and 0.27237 (for peak demand). The normalised elasticities can be treated as coefficients, however the AER has used them to only three significant figures, thus introducing rounding error into the calculations.

- The percentage change in the output quantity index was then worked out as the sum across output categories of the following terms: The growth rate for each output quantity (measured using logarithms), multiplied by the share of each output category in the sum of the estimated, output-related cost elasticities.

- The growth adjustment coefficient, thus derived, was applied by the ESCV in calculations involving the efficiency carry-over mechanism.

- The growth adjustment would help to ensure that distributors were only rewarded for genuine efficiency improvements resulting in cost savings. The objective would be achieved because the operating expenditure data would be expunged of the effects of both a changed customer profile, and variations from forecast in energy usage and peak demand.

18. Demand Management and the DM Incentive Scheme

Key messages

UED's original Regulatory Proposal explained that:

- UED is keen to promote demand management and is seeking to take advantage of technology and equipment developed in the context of the AMI project.
- UED supports the demand management incentive scheme as it provides a stimulus to deliver demand management initiatives. UED will explore a range of demand management initiatives that are tailored to meet customers' needs.
- In addition to its proposed DMIS activities, UED proposed to instigate peak demand management programmes which leverage off the capabilities offered by the Advanced Metering Infrastructure (AMI) project.
- UED will also continue its efforts at broadly-based demand management initiatives, seeking to replicate schemes which have been put into practice in other jurisdictions, and working in conjunction with demand-side aggregators.
- Some demand management initiatives may fail to achieve the forecast benefits. It is therefore important that the AER takes a pragmatic and realistic approach to its assessment of demand management initiatives.
- UED had included $10 million in its building block requirements for demand management initiatives.

In its Draft Decision, the AER:

- Misinterpreted UED's proposed demand management (operating) expenditure as a bid for an increased allowance under the DMIA, equivalent to $10 million over the regulatory control period; and
- Re-iterated the AER's view that the DMIS is intended to provide a modest allowance for innovative and experimental demand management projects which would be unlikely to be approved under the capital spending and operating spending criteria under the NER.
- Asserted that the AER has no grounds to accept that customers are willing to bear a material risk for demand management initiatives that are untested and experimental in nature, and that have not met the expenditure prudency and efficiency tests under the NER.
- Expressed the view that an increase in the DMIA would be outside the scope of the DMIS, and that there was no evidence to suggest that customers were willing to fund an increase of the magnitude apparently sought by UED.
- Confirmed its intention, as set out in the Framework and Approach Paper (AER, 2009e1), to apply the DMIS to the Victorian electricity distributors. The DMIS would be comprised of a part A (the DMIA component) and a part B (the foregone revenue component). Part A would be capped in the forthcoming regulatory control period. The relevant cap for UED would be an annual allowance of $400,000, (summing to $2

million over the regulatory control period).

- Noted that it would be open to UED to propose demand management expenditure under the capital spending and operating expenditure provisions of the NER (refer to page 735 of the Draft Decision).

In this Revised Regulatory Proposal, UED sets forth the following for consideration:

- The business has progressed its plans to investigate and develop demand management initiatives. UED considers that such initiatives would be prudent and efficient mechanisms to moderate the growth in demand across its networks.

- UED supports the DMIS but considers that the sums on offer (at $400,000 per annum) will permit it to trial only a limited number of initiatives and technologies. UED will be constrained in terms of the extent of innovative activity in which it will be able to engage.

- There is a growing recognition that demand management has an important role to play in facilitating the pursuit of energy efficiency, and in ensuring that the distribution network is developed efficiently. Demand management is compatible with broader societal objectives such as reduced energy consumption.

- UED is committed to the changes in business models and work practices that are required in order to bring about a culture of acceptance and application of demand management solutions within the organisation. However, a significant level of injection of expenditure may be required to bring about the necessary transformation.

- UED is committed to the development and implementation of economically viable demand management solutions. The business will therefore act upon the recommendations of the Australian Energy Markets Commission (AEMC) in respect of the development of a demand side engagement strategy. The recommendations were contained in the final report by the AEMC on distribution network planning and expansion (AEMC, 2009j1). UED understands that the AEMC intends to commence consultations on the proposed Rule changes in 2010 so as to give effect to the proposed national distribution planning framework.

- UED expects to develop a demand-side engagement strategy. This activity will be separate from, but nonetheless complementary to the demand management expenditure proposal which UED is currently putting forward.

- Contrary to the AER's assertion that customers are unwilling to fund an increase in demand management expenditure, UED is aware of strong and growing levels of support for spending on demand management education, the provision of information about demand management, engagement with industry, and direct demand management projects.

- The nature of demand management initiatives is such that actual projects, initiatives and their costs and benefits cannot be readily forecast up to five years in advance. Imposing an obligation for such detailed forecasts would amount to a bias against the inclusion of demand management initiatives, and would also be contrary to the National Electricity Objective and the requirements of the NEL and NER.

- In view of recent developments in the electricity distribution sector, (including the AMI rollout, the rapid evolution of smart grid technologies, the anticipated regulatory changes in the areas of demand participation, embedded generation and climate change, and the emergence of new businesses seeking to exploit opportunities in these areas), UED's demand management activities must be flexible. However, as set out in the original Regulatory Proposal, UED's approach includes developing skills, knowledge and resources, promoting changes in customer behaviour, and the evaluation, trial and introduction of appropriate and prudent demand initiatives.

- While there are difficulties inherent in accurately predicting the activities which will take place across the full regulatory control period, indicative information about projects and their customer benefits was provided in the original Regulatory Proposal. More detailed information is contained in this Revised Proposal.
- UED considers that the provision of $10 million of dollars of operating expenditure - in addition to the $2 million available through the DMIS - to cover the demand management initiatives set out in its Regulatory proposal would be both prudent and compliant with the NER requirements.

18.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal explained that UED is committed to the development and implementation of economically viable demand management solutions. In particular, over the next regulatory period, UED intends to:

- Comply with jurisdictional requirements and the proposed new regulatory test (RIT-D) so as to ensure that there is adequate investigation of non-network solutions. UED will consult with affected parties in respect of the non-network options under consideration.
- Continue to develop skills, knowledge and resources so as to be able to exploit economic demand management opportunities.
- Promote changes in customer behaviour, with a view to meeting demand management objectives, through tariff adjustment and reform.
- Continue to evaluate and trial demand management technologies and schemes; and
- Introduce demand management solutions where such solutions provide measurable economic gains or benefits in terms of the functioning of the electricity market. An important caveat on any methods is that UED and its customers should not be exposed to unacceptable levels of risk.

UED's original Regulatory Proposal highlighted three principal elements to its demand management strategy:

- Develop and deliver projects that conform to the requirements of the Demand Management Incentive Scheme (DMIS). A number of these projects will involve customer trials, and UED will pay careful attention to implementation so as to ensure that the costs of running the trials qualify for reimbursement under the Demand Management Innovation Allowance (DMIA).
- Instigate peak demand management programmes to leverage off the capabilities offered by the Advanced Metering Infrastructure (AMI) project.

- Broadly-based demand management initiatives, seeking to replicate schemes that have been put into practice in other jurisdictions, and working in conjunction with demand-side aggregators.

UED reported on the additional operating expenditure in relation to demand-side programmes and also noted indicative savings in capital expenditure which are shown in Table 18-1.

Table 18-1: Forecast activity on tailored demand-side response programmes

Year	Number of investigations (indicative)	Investigation costs ($M)	Number of programmes fully underway (cumulative)	Operating expenditure incurred ($M)	Value of capital spending deferred ($M)
2011	3	$0.06	2	$0.50	$0.75
2012	3	$0.06	4	$1.00	$1.50
2013	3	$0.06	6	$1.50	$2.25
2014	3	$0.06	8	$1.50	$2.25
2015	3	$0.06	10	$1.50	$2.25
Totals	**15**	**$0.30**	**10**	**$6.00**	**$9.00**

Source: Estimates provided by Energy Response. Amounts shown in real 2010 prices ($ 2010 million).

Notes (1) Operating expenditure will be spent in the year in which it is recorded.

(2) The timetable for the realisation of savings resulting from the deferral of capital expenditure cannot be specified precisely. The timing may differ somewhat from that reported here.

(3) Other core demand management projects will be undertaken by UED, and the costs of these are not incorporated into the figures shown in the table. The projects include direct load control, critical peak pricing and standby generation.

UED's tailored response to demand management means that the methods employed to reduce demand will vary depending upon the profile of users, and the options that are available in a particular area. UED noted that its energy efficiency initiative would include:

- Lighting upgrades.
- More efficient heating and cooling management strategies.
- Building management control system modifications.
- The installation of more efficient air conditioning plant and monitoring systems.
- Efficient lighting and controls.

UED noted that customer education will be important, particularly in the commercial sector, because building owners and property managers typically focus on overall energy usage, rather than peak demand.

UED highlighted the following customer benefits from demand-side participation:

- Free energy audits.
- Financial incentives to reduce peak power demand.

- Assistance to implement approved initiatives.
- Reduced electricity costs through improved energy efficiency.
- Better environmental performance reported by the establishment.
- The opportunity to enter into a financial arrangement to implement various projects with no upfront cost; and
- Improved security of electricity supply achieved via a general amelioration of peak demand.

UED noted that there are two principal components to the DMIS:

- Part A. This is a demand management innovation allowance (DMIA) which is offered to the DNSP as an *ex ante*, annual monetary sum. The DMIA is a fixed amount of additional revenue which is made available at the commencement of each regulatory year of the regulatory control period.
- Part B. This component allows a DNSP to recover the revenue foregone in a regulatory period as a result of the successful implementation of a project approved under Part A of the scheme. The revenue losses arise from lower delivered energy volumes that are directly attributable to the take-up of the demand management project. Part B can only be applied to a DNSP if Part A is already in operation. Part B will not be applied automatically and cannot operate in isolation.

UED noted the possibility that some demand management projects may fail to yield the expected benefits, while others may provide benefits but not within the foreshadowed timeframes, or within the time horizon of a single regulatory control period. It is therefore appropriate that the AER takes a pragmatic and realistic approach to its assessment of demand management initiatives.

UED included an increment of $10 million (in real 2010 values) intended to reflect the forecast expenditure on demand management operational expenditure. . This amount will affect the calculation of the annual revenue requirement (in the PTRM model) for each regulatory year of the next regulatory control period.

UED's forecast operating expenditure on demand management projects is provided below in Table 18-2.

Table 18-2: Forecast operating expenditure on demand management

2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
0.7	1.8	2.5	2.5	2.5

Source: Estimates prepared by UED. Amounts shown are in $ 2010 million. The operating spending shown in the table has been incorporated into the baseline operating expenditure forecasts which have been put forward by UED as part of this Revised Regulatory Proposal.

18.2 AER's Draft Decision on the demand management incentive scheme

Although UED explained in its original Regulatory Proposal that the DMIS was one of only three principle elements in its demand management strategy, the AER interpreted UED's proposed operating expenditure as an application to have its allowance under the DMIS increased to a total of $10 million over the forthcoming regulatory control period. The AER then noted that the DMIS is not the only potential source of funding for demand management initiatives. The AER had stated previously that distributors could propose operating spending and capital expenditure allowances to fund demand management expenditure, and that this expenditure would be assessed under the operating spending and capital expenditure criteria contained in clauses 6.5.6 and 6.5.7 of the NER.

The AER also restated its view that the DMIS is intended to provide a modest allowance for innovative and experimental demand management projects which would be unlikely to be approved under the opex and capex criteria under the NER. Although UED did not actually seek an expansion of the DMIS, the AER retorted that it had not been provided with evidence to show that customers were willing to bear a material risk for unproven and experimental demand management initiatives. The AER claimed that the particular initiatives under consideration would not have met the expenditure prudency and efficiency tests under the NER.

UED regrets the confusion that may have been caused by an inadvertent and inappropriate reference to the "DMIS" building block component in section 18.6.4 of its initial Regulatory Proposal.

The AER considered that an increase in the DMIA to $10 million would be beyond the scope of the DMIS. Under clause 6.6.3(b) of the NER, the AER must consider, among other matters, the willingness of customers to fund increased costs incurred through the implementation of a DMIS. The AER stated that, in its view, there was no evidence to suggest that customers would be willing to fund the increase which the AER believed was being sought by UED. The AER then determined not to increase the allowance provided to UED under the DMIA.

The AER maintained its position, as set out in its Framework and Approach Paper, to apply the DMIS as proposed to UED. The DMIS will be comprised of a part A (the DMIA component) and a part B (foregone revenue component). Part A will be capped in the forthcoming regulatory control period. The relevant annual cap for UED will be $400 000 ($2 million over the regulatory control period).

The capped amount will be allocated to UED as an ex-ante allowance, in five equal instalments. The ex-post review and operation of the DMIA will be as set out in the DMIS. Part B will be uncapped but subject to the restrictions set out in the DMIS. Part B will be applied consistent with the methodology set out in the DMIS

Finally, the AER noted that it is open to UED to propose demand management expenditure under the capex and opex provisions of the NER. The AER did not however assess UED's proposed expenditure on this basis.

18.3 UED's response to the AER's Draft Decision on the demand management incentive scheme

18.3.1 UED's commitment to Demand Management

UED remains eager to explore and develop demand management initiatives and it considers that such initiatives are prudent and efficient mechanisms to address growth in demand across its networks. Indeed, with the continued growth in peak demand, combined with reductions in growth in overall energy usage, appropriate demand management initiatives have the greatest potential to prudently and efficiently meet customer requirements across the network while also delivering industry and economy wide benefits such as reduced losses, increased reliability and stability, reduced capital expenditure requirements for new generation and transmission investment, improved opportunities for renewable generation and reduced emissions.

There is a growing recognition that demand management has an important role to play not only in enabling the efficient development of the distribution network, but also in ensuring that the country's (and the energy industry's) climate, energy efficiency, environmental and economic objectives can be achieved. This recognition is leading to a fundamental re-examination of the manner in which electricity distribution networks are planned, constructed, operated and regulated.

UED recognises that in order for demand management to be implemented on a broader scale over time, changes will need to be effected to organisational culture and business practices. The business is willing to embrace change and has always been at the forefront in terms of developments in organisational structure and management arrangements, and the installation of new technologies.

The types of change which will need to be implemented will include how the business plans for network development, and the way in which assessments are made of the relative merit of network and non-network alternatives. Data collection processes will need to be established in the first instance so that information can be gathered about network performance and network requirements from a demand management perspective. UED isn't suggesting that a major paradigm shift is needed. However, there will be a need to drive transformation, and hence there will be significant activity (and expenditure) over the regulatory control period.

UED emphasises that it is committed to the changes in business models and work practices that are required in order to bring about a culture of acceptance and application of demand management solutions within the organisation.

18.3.1.1 Demand management (DM) business unit

UED will create a DM Business Unit reporting to the Chief Operating Officer. This team will be responsible for developing and implementing UED's DM strategy. The team will:

- Investigate and establish a DM trial plan.
- Develop and deliver small-scale DM projects.

- Make use of the outcomes from trials to develop fully-fledged project plans which can be integrated into the Regulatory Proposal for the 2016 to 2020 regulatory control period.

18.3.1.2 Overview of the demand management (DM) trial plan

UED will instigate trials for the large and small customer segments. At the outset, priority will be given to solutions which encompass:

- Distributed generation by large customers (covered under broad-based initiatives).
- Voluntary load curtailment by large customers (covered under broad-based initiatives).
- Measures to leverage the smart metering infrastructure in place for residential and farming customers (part of the AMI data project discussed below).
- Direct load control for small customers (covered under broad-based initiatives).

Distributed generation and voluntary load curtailment by large customers are proven solutions. However, there is a need to investigate the full potential for take-up of these demand control measures by customers within the UED distribution region. At present, the unknown variables consist of: The availability and spread of the generation resource, customer willingness to participate in the programmes, the likely costs of engagement, the suitability of existing technologies, and the expected ease of integration of DM capacity with UED's existing network operations.

Another proven solution is direct load control, and in this instance, the uncertainties pertain to customer acceptance, the costs of implementation, and the likely penetration into UED's distribution area.

The potential solutions surrounding smart meters and home area networks are promising but nonetheless still nascent. Comprehensive testing is required to assess the viability of these solutions.

The trials will be designed in such a way as to ensure that UED develops a number of platforms from which activities can be scaled for broad implementation across its service area. The platforms will be integrated with network planning, system operations, marketing, and customer service.

18.3.1.3 Using DM Capacity

The DM capacity that is developed under the various trial programmes will be incorporated into normal operational plans such as the summer readiness plan.

18.3.2 Role of the DMIS

UED supports the DMIS but believes that the scheme will enable experimentation with only a limited number of initiatives and technologies. When taken in isolation, the trials will be insufficient to facilitate an optimal rate of take-up of demand management solutions. over the 2011 to 2015 regulatory period. The matters to be included in the trials, and some of the expected benefits, were detailed at length in the original Regulatory Proposal. These trials will be conducted on a regional, staged and targeted basis. UED will also be seeking to engage with customers, industry participants and demand response proponents so as to seek their input into project design and implementation under the DMIS.

The purpose of these trials will be to investigate more efficient or effective methods of implementing already proven demand management activities or to identify new methods of undertaking demand management. The trials funded under the DMIS will also inform UED's expenditure decisions under its proposed broadly based demand management initiatives set out below.

18.3.3 Budgetary allocation to specific projects.

As explained above UED believes that it is important to maintain a flexible approach to demand management initiatives and it is conceivable that following industry consultation and the finalisation of the regulatory arrangements applicable to demand management that the projects under consideration will vary in terms of the details of their final implementation. However, UED considers that the projects, in the form in which they are currently proposed, represent both necessary and prudent operational expenditure.

A summary of some of the Projects that UED is planning to implement across the regulatory control period and their expected benefits are set out below.

18.3.3.1 Use of AMI information for Demand Management purposes

Traditionally demand calculations have been restricted to broad scale areas served by SCADA equipment (i.e. less than 1,000 zones across the UED network), with demand calculations for smaller zones or individual customer classes determined by interpolation or other approximations. However, the roll-out of advanced metering infrastructure (AMI) will enable UED to collect data on peak demand usage from each of its approximately 620,000 customers.

UED plans to undertake activities in this area including integrating the substantial information available from the AMI Rollout on the performance of the network and the incidence and location of peak demand events, and making this information available to network planners for planning purposes, and ultimately more generally to enable industry participants to identify potential non-network alternatives.

Over the regulatory control period, UED will develop an approach to efficiently and effectively gathering demand data and establishing the systems and protocols necessary to make it available across the business and to the industry more broadly, as appropriate.

Based on its own assessment of the costs involved in this process, supported by analysis undertaken in connection with its *Smart Grid, Smart City* proposal and advice from Secure Energy and Secure Partners, UED has estimated that expenditure of at least $1m will be required for this project. The forecast profile of expenditure on the utilisation of AMI data for demand management is shown in Table 18-3.

Table 18-3: Forecast operating spending on AMI data project

2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
0.0	0.25	0.35	0.35	0.05

Source: UED Estimates supported by information provided by Secure Energy and Secure Partners. Amounts shown in real 2010 terms.

Notes (1) Operating expenditure at a lower level will commence in the second year as system solutions are being identified and discussed with industry; spending will grow over the next two years as systems are developed and implemented and will then settle to a lower level as they are bedded down into " business as usual" practices.

(2) This proposal assumes that the expenditure will be mainly comprised of direct operational expenditure for contractors and consultants. The actual spending may be on a mix of consultants, contractors and direct labour with the ultimate breakdown determined in accordance with UED's "Make/Buy" decision framework (see Figure E5 in the Executive Summary of the original Regulatory Proposal)

Although difficult to describe with precision, there are benefits that can be achieved by having greater access to more granular and accurate demand data. UED is confident that the benefits to customers and the industry will substantially exceed the proposed costs. For example, if access to this data permits UED to delay major expenditure on one or two reinforcement activities by only one year, then the benefits would exceed the costs substantially. If provision of the data to industry enables new or innovative non-network solutions to be demonstrated as effective as proposed network solutions, then the benefits would be even greater. It is exactly these types of benefits that underpin (in part) the decision to undertake the AMI rollout and to not undertake these benefit realisation activities would place customers at risk of funding the rollout without receiving the full measure of the expected benefits.

18.3.3.2 Critical Peak Pricing

UED has been a pioneer in implementing innovative tariff structures to address network loading issues. The Summer Demand Incentive Charge was in effect the first Critical Peak Pricing tariff introduced at a distribution level within Australia. UED's experience has demonstrated that such tariffs can play a role in ameliorating emerging network constraints. However their impact is severely limited unless there is full engagement with retailers and customers to ensure that the expected behavioural changes can be achieved.

UED expects to address additional Critical Peak Pricing methodologies later in the regulatory control period. As part of this process it has identified the need for modest expenditure on collecting data, and to cover the costs of presenting proposals to the industry and to retailers. In light of the significant benefits which can be gained from Critical Peak Pricing, this expenditure is also aimed at supporting a more detailed engagement with these parties so as to ensure that solutions are acceptable and workable and therefore more likely to achieve the expected benefits.

UED considers that the modest expenditure of $0.5m on the development of Critical Peak Pricing tariffs and engaging with industry and retailers to ensure that desired impacts are achieved is prudent and appropriate. In light of the importance of the AMI rollout to this initiative and the need for retailers and others to develop systems and processes to implement such tariffs, UED expects that this project will be implemented only in the latter years of the regulatory control period. Table 18-4 sets out the forecast expenditure profile on the scheme to develop critical peak pricing by engaging with other parties.

Table 18-4: Forecast operating expenditure on Critical Peak Pricing

2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
0.0	0. 0	0.0	0.05	0.45

Notes (1) Operating expenditure will primarily be direct operational expenditure for contractors and for consultation processes.

18.3.3.3 Demand Management engagement and the new Regulatory Test

The traditional industry approach to network development has been to fully plan to meet future demand from network solutions and to then pursue non-network solutions. It is now recognised that non-network solutions should form part of the assessment of possible solutions at a much earlier stage in the process.

This bringing forward of the assessment of non-network alternatives is a key driver of the regulatory changes currently being proposed, notably the new regulatory tests (the RIT-D and the RIT-T) and the demand side engagement requirements recommended by the AEMC in their Final Report (AEMC, 2009j1).

Unfortunately while electricity distribution businesses have well-developed systems for collecting, assessing and developing network solutions the same is not generally true for non-network solutions.

If the demand-side engagement strategy and the new regulatory test are to achieve the predicted benefits in improved efficiency and reduced costs, then UED will need to ensure that similar information becomes available and is assimilated across the business and the industry to ensure that non-network alternatives can be developed and assessed in a timely manner and with equivalent opportunity of being implemented with network solutions. The collection, analysis and dissemination of appropriate data for non-network solutions is not a trivial exercise. In the case of network solutions, data compilation systems have evolved over decades, and there is an embedded knowledge base among staff.

UED recognises that it would not be efficient or prudent to immediately set out to collect, analyse and disseminate a substantial new set of data to support demand management, increased industry expectations and the new regulatory requirements. Instead, UED expects to develop new systems, processes and data dissemination approaches carefully over the regulatory control period in consultation with the industry. In addition, UED expects that these new processes and systems will be informed by the developments being undertaken across the industry including other demand management and smart grid trials.

The proposed regional approach of trialling demand management initiatives on a staged basis, as set out in the original Regulatory Proposal, was an example of the cautious and incremental approach which UED expects to apply to these initiatives. A consequence of this prudent approach is that while a great deal of effort will need to be expended to achieve the desired outcome of greater engagement, and to be able to leverage off evolving industry approaches, it would be imprudent, and contrary to the regulatory intent, to specify in advance the very activities that the process is designed to discover.

It is these additional activities and additional operational expenditure requirements, driven by the step change in regulatory requirements, industry developments (e.g. smart grid and AMI) and industry expectations that this expenditure is (in part) intended to cover. UED has estimated that at least $0.75 million will need to be spent on these particular activities. The expected expenditure profile is set out in the following table. Table 18-5 shows forecast operating spending on establishing systems and collecting information necessary to support the RIT-D, and the demand-side engagement strategy.

Table 18-5: Forecast operating expenditure on systems and information collection

2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
0.00	0.1	0.20	0.15	0.05

Source: UED Estimates supported by information provided by Secure Energy and Secure Partners. Amounts shown in real 2010 terms.

Notes (1) Operating expenditure will commence in the second year as system solutions are being identified and discussed with industry, and will grow in the next year as systems are developed and implemented and will then gradually reduce to lower levels as they are bedded down into " business as usual" practices and the business and industry becomes more accustomed to new methods of operating.

(2) This proposal assumes that the expenditure will be primarily direct operational expenditure for contractors and consultants. The actual expenditure may comprise a mix of consultancies, contractors and direct labour with the ultimate .breakdown determined in accordance with UED's "Make/Buy" decision framework (see Figure E5 in the Executive Summary of the original Regulatory Proposal)

18.3.3.4 Broad-Based Demand Management initiatives

As set out in the original Regulatory Proposal, UED is proposing to implement broadly-based demand management initiatives, seeking to replicate schemes that have been put into practice in other jurisdictions, and working in conjunction with demand-side aggregators. UED has allocated $6 million over the regulatory control period for these activities. The expected expenditure profile is set out in the following table. Table 18-6 presents the likely trajectory of expenditure on broad-based demand management initiatives.

Table 18-6: Forecast operating expenditure on Broad Based initiatives.

2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
0.50	0.50	1.50	1.50	1.50

Source: UED Estimates supported by information provided by Energy Response and Secure Energy. Amounts shown in real 2010 terms.

Notes (1) Operating expenditure will be lower in the initial years to allow for the identification of the most appropriate areas with the maximum opportunity for effective demand response benefits. The staged approach will also allow the proposed activities to be informed by the outcomes of the demand management investigations and trials being undertaken under the DMIS.

(2) Although UED is aware that there are at least two organisations that can provide services in this area, the actual expenditure will be allocated pursuant to UED's normal contract procurement procedures to ensure that the maximum benefit at the most prudent cost is achieved.

The benefits of demand response as a means of reducing peak demand and therefore deferring or avoiding network expenditure are now reasonably well established. Indeed, there are several businesses in Australia which are dedicated solely to supporting the electricity industry in this way.

The proposed regulatory changes, the perceived greenhouse gas benefits of demand response compared to network solutions, the ability of demand response to support and complement renewable energy solutions and its ability to lower capital expenditure requirements at a time when the industry is facing a “bow wave” of replacement and reinforcement expenditure are likely to lead to even greater participation in this type of activity over the regulatory control period.

UED has confirmed with Energy Response and with Secure Energy, Australia's leading specialist demand response organisations, that a programme of the size envisaged by UED can be implemented within the UED area, and deliver significant benefits. Indeed these benefits are likely to be greater than the limited deferral benefits set out in the original Regulatory Proposal.

Contrary to the AER's assertion that customers are unwilling to fund an increase in demand management expenditure, UED is aware of strong and growing levels of support for spending on demand management education, the provision of information about demand management, engagement with industry, and direct demand management projects.

Indeed it is worth noting, if only in passing, that the AER's Draft Decision confirms that there were a number of submissions which presented arguments for an expanded DMIA[122]. The AER did not discuss these submissions in any depth.

Anecdotal evidence suggests that consumers are prepared to fund modest initiatives which produce external or ancillary benefits such as reduced emissions, improved environmental and safety outcomes, and, in some cases, even improved social equality. That the activities proposed by UED are likely to lead to such benefits suggests that a reasonable level of support from customer groups can be expected.

But the issue becomes moot when it is recognised that these proposed activities are in fact a prudent and efficient approach to managing the issues facing the network, and are likely to lead to lower costs and improved service for customers. Rather than there being “no evidence to suggest that customers are willing to fund an increase as proposed by United Energy”, there are submissions and evidence available to the AER in support of such expenditure and no evidence to the contrary.

18.3.3.5 Demand Management Team

Experience within UED, and across the industry, has demonstrated that achieving changes in processes, system and culture requires dedicated effort. UED is committed to being a leader in providing customers and the industry with the benefits that effective, efficient and prudent demand response activities can deliver.

UED considers that such benefits can only be delivered in a sustained, prudent and efficient manner if there is a dedicated team within the organisation to develop and share the skills and resources necessary for effective demand management processes. The skills and capabilities required are supplementary to the traditional skills required within an electricity distribution business.

A small, efficient team will be charged with championing demand management solutions within the business; ensuring that non-network proponents have access to appropriate

[122] Examples of applicable submissions include those by the Victorian Employers Chamber of Commerce and Industry (VECCI) and the Central Victorian Greenhouse Alliance (CVGA).

information; and developing, assessing and managing the demand management projects set out above.

UED considers that at a minimum this requires a senior manager reporting to the Chief Operating Officer and, for the four year period when the majority of the projects are underway, one senior project manager. UED estimates that the costs of hiring and retaining an appropriate staff complement would amount to $2 million dollars across the regulatory control period.

Table 18-7: Forecast operating expenditure on Demand Management Team

2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
0.20	0.45	0.45	0.45	0.45

Source: UED Estimates. Amounts shown in real 2010 terms.

Notes (1) Operating expenditure will commence part way through the first year with the appointment of a senior manager (estimated annual cost of $250,000) followed by the appointment of the senior project manager in the second year ($200,000).

18.4 Conclusion

While it is not possible to specify with precision the activities that will take place across the full regulatory control period, indicative information as to the expected activities and customer benefits was provided in the original Regulatory Proposal and further information is provided in this Revised Proposal.

UED considers that the provision of $10 million of operating spending (which is in addition to the $2 million set out for the DMIS) to cover the demand management Initiatives set out in its Regulatory proposal is prudent operating expenditure which is fully compliant with the NER requirements.

Table 18-8 presents a summary of UED's proposed demand management operating expenditure and DMIS allocation.

Table 18-8: Forecast operating expenditure on Demand Management activities

Activity/Project	2011 ($M)	2012 ($M)	2013 ($M)	2014 ($M)	2015 ($M)	Total ($M)
Use of AMI data for Demand Management	0.0	0.25	0.35	0.35	0.05	1.0
Preparations for Critical Peak Pricing	0.0	0.0	0.0	0.05	0.45	0.50
Systems and Data to support RIT-D and demand participation engagement	0.0	0.10	0.20	0.15	0.05	0.50
Broad Based Demand Management Initiatives	0.50	1.0	1.50	1.50	1.50	6.0
Demand Management Team	0.20	0.45	0.45	0.45	0.45	2.0
Total Baseline Operational Expenditure	0.70	1.80	2.5	2.5	2.5	10.0
Investigation costs included in DMIA	0.06	0.06	0.06	0.06	0.06	0.30
Other DMIA projects	0.34	0.34	0.34	0.34	0.34	1.70
Total DMIS (Part A)	0.40	0.40	0.40	0.40	0.40	0.40

19. Pass through events

Key messages

UED's original Regulatory Proposal explained that:

- Pass through provisions for defined events and nominated events should be applied to both standard control and alternative control services.
- If a materiality threshold is to apply then UED's proposes that it should be no more than $200,000 for each occurrence of a specific nominated pass through event.
- For general nominated pass through events, UED proposes that the materiality threshold for each occurrence should be evaluated as one per cent of annual average revenue, or a fixed amount of $3 million, whichever is the lower.
- UED proposed a number of nominated pass through events for the forthcoming regulatory control period.

The AER's Draft Decision accepted only a limited number of specific nominated pass-through events, and has determined a high materiality threshold of one per cent of the smoothed revenue forecast.

In this Revised Regulatory Proposal, UED explains that:

- The AER is acting outside of the Rules in setting a materiality limit that is 1 per cent of revenue
- It has removed the pass through event for line clearances in favour of an opex forecast allowance
- Has nominate a natural disaster event to include events

19.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal noted that clause 6.6.1 of the Rules sets out the provisions relating to the pass through of costs and savings associated with positive pass through and negative pass through events, respectively. In addition, chapter 10 of the Rules defines the following four pass through events:

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a terrorism event.

UED supported the AER's approach of approving two types of additional pass through events:

- a 'general' nominated pass through event; and
- additional 'specific' nominated pass through events.

An event is considered to be a general nominated pass through event where it meets the following criteria:

- an uncontrollable and unexpected event occurs during the forthcoming regulatory control period, the effect of which could not have been prevented or mitigated by prudent operational risk management; and
- the change in costs of providing distribution services as a result of the event is material.

UED's original Regulatory Proposal accepted that a materiality threshold should apply to a general nominated pass through event. However, UED disagreed with the AER's view that the threshold should be based solely on annual revenue.

UED instead proposed that the materiality threshold should be one per cent of annual average revenue, or a fixed amount of $3 million, whichever is the lower. UED also proposed that the materiality threshold should apply to the sum of the costs arising out of an event, rather than simply to the costs which are recorded in a specific year. A common sense assessment of the overall impact of an event would lead to greater certainty about a distributor's ability to recover the legitimate costs borne by the business.

In addition to the four stipulated events, UED noted that the Rules permit a DNSP to nominate events which, in the opinion of the business, should be classified for the distribution determination as pass through events. These additional pass-through events are defined by the AER as "specific nominated events". UED nominated the following specific nominated events:

- the transfer of customer regulation to a national regulatory framework;
- the introduction of an emissions trading scheme;
- changes in taxes or other levies;
- the introduction of new regulations for vegetation management around power lines;
- changes to the bushfire mitigation framework;
- climate change assumptions being materially wrong;
- financial failure of a retailer;
- retailer of last resort; and
- a national broadband network event.

For each of these events, UED proposed that the materiality threshold should be the administrative costs of assessing the pass through application or a fixed amount of $200,000, whichever is the lower.

19.2 Draft determination on pass through events

19.2.1 AER's criteria for nominating pass through events

In its Draft Determination, the AER moved away from the approach to nominating pass through events very recently applied in the Queensland and South Australian distribution determinations and also applied previously in the NSW and ACT distribution determinations.

Previously it had been the AER's view that:

- nominated pass through events should be divided into two categories based primarily on the probability of the event occurring during the regulatory control period, namely: (i) specific nominated pass through events (highly likely to occur), and (ii) general nominated pass through events (unexpected events); and
- in determining specific nominated pass through events, while eight criteria were identified, the likelihood of occurrence of an event and the DNSP's degree of control over the event were the most significant factors.

The AER now considers that a probability-based criterion is no longer relevant to the assessment of pass through events. Consequently, the AER has rejected the general nominated pass through event for DNSPs on the grounds that such events:

- are likely to undermine incentive arrangements within the regulatory regime; and
- may not be foreseeable in that the nature or type of event often cannot be clearly identified.

As a result, the AER has substituted the following criteria for nominating pass through events:

- the event is not already provided for by the defined events in the Rules, through opex, through WACC or any other mechanism;
- the event is foreseeable;
- the event is uncontrollable;
- the event cannot be self-insured;
- the party who is in the best position to manage the risk is bearing the risk; and
- passing through the costs of the event would not undermine the incentive arrangements within the regulatory regime.

The AER considers that events that in the past may have been considered under the general pass through event category could be captured through the inclusion of a 'natural disaster' specific pass through event. The AER argues that such an approach will capture all major uncontrollable costs of a high magnitude, while creating further regulatory certainty for the Victorian DNSPs.

19.2.2 AER's rejection of certain nominated pass through events

On the basis that it would be inappropriate to accept events relating to possible new, changed or removed regulatory obligations that are already within the scope of the 'regulatory change event' or 'service standard event.', the AER has rejected the following specific pass through events nominated by UED:

- an emissions trading scheme event;
- a transfer of customer regulation to national regulatory framework event;
- an introduction of new regulatory obligations for vegetation management around powerlines event;
- a changes to bushfire mitigation framework event;
- a national broadband network event; and
- a change in corporate income tax event.

The AER has rejected the 'change in corporate income tax event' proposed by UED on the grounds that the Rules explicitly exclude corporate income tax changes from the definition of a tax change event.

The AER has rejected the 'climate change assumption being materially wrong' event proposed by UED on the basis that it cannot be clearly identified and defined in advance, it undermines the incentive properties in the regime, and that it is not uncontrollable and not of a high magnitude.

The AER has rejected the 'financial failure of a retailer' event as proposed by UED on the basis that it considers the appropriate method to mitigate against the risk of this event is through the prudential requirements contained in clause 6.21.1 of the Rules.

The AER has rejected the force majeure event proposed by UED on the basis that these types of events will likely be captured in the 'natural disaster' event.

19.2.3 Pass through events nominated by the AER

The AER did accept:

- a pass through for a retailer of last resort event as proposed by UED;
- an insurance event/legal liability above insurance cap event; and
- an insurer credit risk event.

The AER also nominated a natural disaster event as a pass through event on the grounds that the occurrence of natural disasters such as floods, earthquakes, and major storms is entirely beyond the control of the DNSPs. The timing of such an event cannot be determined in advance. Costs incurred as the result of a natural disaster depend on several variables, such the type of event, the magnitude of the event, and the areas of the DNSP's network which are affected (and the extent to which they are affected).

19.2.4 Materiality threshold

The AER has assessed the administrative costs threshold which it has applied in previous distribution determinations to be erroneous.

In its place the AER is proposing that the materiality threshold for nominated pass through events should be 1 per cent of the smoothed forecast revenue in the years of the regulatory control period that the costs are incurred. The AER argues that this threshold:

- is consistent with the purpose of a materiality threshold to reduce the administrative burden of excessive application for pass through events, while still including events which may materially affect the business;
- has been applied to the general nominated pass through event in previous distribution determinations; and
- is the same threshold prescribed under the Rules for transmission cost pass throughs.

19.3 UED's response to the AER's draft determination on scope of pass through events

UED considers the AER's draft position to be generally unreasonable. What is being proposed is not consistent with the objective of the pass through provisions or with the national electricity objective and revenue and pricing principles. It erroneously seeks to ensure consistency with transmission regulation, while at the same time being inconsistent with its recent decisions in distribution.

UED reiterates its position that efficient investment in the industry, and the promotion of the interests of consumers, will be facilitated by a well-structured and comprehensive pass through regime. Regulated distribution businesses should not be compelled to bear remote risks over which the business cannot exert control.

19.3.1 Rule requirements

The objective of the pass through provisions is to provide a degree of protection for DNSPs from the impact of uncontrollable changes in costs that arise during a regulatory control period. The pass though mechanism recognises that an efficient revenue allowance cannot be established with complete certainty at the time of its final determination, and that it may not be efficient to require DNSPs to manage all situations or circumstances without this revenue allowance.

The appropriate mechanism for the recovery of costs that are uncontrollable (or controllable but of a high magnitude) is through the pass through events. Sections 7A (2)(a) and (b) of the NEL provide that DNSPs should be able to recover at least the efficient costs the operator incurs in providing direct control network services and complying with regulatory obligations or requirements.

The costs of unforeseeable occurrences, and the unforeseeable timing and/or cost of foreseeable events, should be passed on to consumers as and when the events occur, rather than in anticipation of an event. UED believes that the interests of consumers are best served by a pass through regime which conforms to these principles.

The pass through events in question do not present themselves in a form which is amenable to standard methods of risk quantification. There are no satisfactory techniques available for forecasting the potential costs and for identifying likelihood and incidence of the pass through events in question. Such events are ill-suited to incentive regulation, and a pass through offers the cheaper option, or possibly the only option.

In other cases, insurance is an appropriate means of addressing the risk of possible cost increases resulting from unexpected events. However, insurance coverage is often only partial, or else cannot be obtained at reasonable and justifiable rates. In addition, insurance policies are not available for the types of events for which risk quantification cannot be achieved. This is because of uncertainty about whether or not the event will occur, and, if it does occur, when it will happen and what the associated costs will be.

Hence, in circumstances in which insurance is not a feasible or sensible proposition, an efficient outcome is to permit the costs (or savings) associated with unforeseen events and the unforeseeable timing/cost of foreseeable events to be passed through. UED believes that if the business has no capacity to influence the environment which gives rise to certain risks, then the resultant costs (or savings) should be passed through to the customer.

19.3.2 The AER should not reject the general nominated pass through event

AER has consistently approved a 'general' nominated pass through event. An event is considered to be a general nominated pass through event where it meets the following criteria:

- an uncontrollable and unexpected event occurs during the forthcoming regulatory control period, the effect of which could not have been prevented or mitigated by prudent operational risk management; and
- the change in costs of providing distribution services as a result of the event is material.

The AER now rejects the general pass through event as a nominated pass through event. The AER's explanation for this change in position is two-fold:

- it now accepts that 'forseeability' should be viewed in terms of whether the event is capable of being tightly defined in advance rather than the probability of the event occurring; and
- the removal of the general pass through event – and its replacement with a natural disaster event – is necessary to minimise regulatory discretion during the regulatory control period.

UED considers the AER's rejection of the general pass through event to be inconsistent with its inclusion of this event in each of its recent Distribution Determinations in the ACT, NSW, South Australia and Queensland. Permitting a general pass through event for distributors in other jurisdictions, but rejecting it for Victorian distributors, is not a reasonable outcome.

Moreover, it is UED's view that achievement of the national electricity objective and the revenue and pricing principles will be hindered by the AER's establishment of a criterion for a nominated event that it be foreseeable in that the nature or type of the event can be clearly identified. The AER's reliance on this criterion is inconsistent with the purpose of conferring on the AER a power to nominate pass through events in distribution determinations. In addition it gives insufficient weight to the objective of the pass through provisions that DNSPs should be permitted to pass through uncontrollable costs, even where events arise during the regulatory control period that cannot be clearly identified at the time of the AER's determination. Unlike TNSPs, there is no provision in the Rules which enables DNSPs to reopen revenue caps and pass through to consumers the costs of an event which arises during the regulatory control period which is beyond the reasonable control of the provider.

Having a natural disaster event does not provide protection to DNSPs for all kinds of events which would fall within a general pass through event.

The fact that there has not been a consistent approach by jurisdictional regulators to defining pass through events for distribution shows that it is difficult to anticipate with any certainty the kinds of pass through events which may arise in distribution over the regulatory control period. Given this uncertainty, UED considers it important to have a general pass through event category. Failing this, what is required are a greater – not lesser – number of specific nominated events.

UED submits that it is unreasonable of the AER to refuse to nominate a pass through for a general pass through event.

19.3.3 Regulatory change or service standard events

The AER has also suggested that it would not be appropriate to nominate as specific pass through events any event that already falls within one of the specified pass through events in Chapter 10 of the Rules. Narrowly interpreted this is not unreasonable. However, the AER's stance is opposed to nominating as specific pass through events any events which *could* be classified as regulatory change events or service standard events. This does not seem reasonable.

In its regulatory proposal, UED raised the possibility that a 'regulatory change event' could be confined to changes in existing regulatory obligations and might not encompass the removal or imposition of a new regulatory obligation or requirement. The fact that the AER accepted this argument is evidence that reliance on the pass through events specified in the Rules is not sufficient. However the AER has formed the view that the service standard event could capture the pass through of material cost increases or decreases relating to the imposition of new regulatory obligations. UED does not agree.

There is no certainty that new regulatory obligations arising during the regulatory control period will meet the criteria for a service standard event. Moreover, UED considers that there is a flaw in the way in which the AER has interpreted the meaning of 'service standard' event under the Rules. Specifically, a service standard event carries with it the condition that the event should substantially affect the manner in which the DNSP is *required* to provide a direct control service. The AER has suggested a transfer of customer regulations to a national regulatory framework would constitute a service standard event, when in fact, the only change would be to the commercial and legal environment in which UED operates in the course of providing distribution services. Such an event would not go to the manner in which UED is required to provide a *direct control service*.

Far from providing certainty, the AER has increased uncertainty about what type of events might fall within the scope of either the 'regulatory change event' or 'service standard event' specified in Chapter 10 of the Rules.

If it is uncertain about whether a particular event falls within the category of regulatory change event or a service standard event, the AER should treat these events as nominated pass through events. Consistent with the requirements of the NEL and Rules, the inclusion of these events as nominated pass throughs will help to ensure that UED is provided with a reasonable opportunity to recover its efficient costs, and has effective incentives in order to promote economic efficiency.

For example, the AER has rejected UED's proposed nominated pass through arising from bushfire mitigation recommendations arising from the Royal Commission into the Victorian Bushfires on the basis that it could relate to possible new, changed or removed regulatory obligations that are either within the scope of the 'regulatory change event' or 'service standard event'.

It is not clear what form the recommendations of the Royal Commission will take and what steps Victorian DNSPs will be required to take as a result of those recommendations. It is therefore far from definite that the recommendations arising from the Royal Commission will fall within the category of regulatory change event or service standard event. Those recommendations are, however, likely to have a material cost impact on Victorian DNSPs.

Consistent with the purpose of the pass through provisions, Victorian DNSPs should not be required to bear the burden of the costs of activities undertaken in response to those recommendations through the pass through mechanism. A pass through for recommendations arising from the Royal Commission into the Victorian Bushfires is consistent with the requirements of the NEL and Rules. The inclusion of this event would help to ensure that UED is provided with a reasonable opportunity to recover its efficient costs, and has effective incentives in order to promote economic efficiency. UED submits that it would be unreasonable of the AER to refuse to nominate a pass through for recommendations arising from the Royal Commission into the Victorian Bushfires.

19.3.4 Financial failure of a retailer event

The AER rejected the financial failure of a retailer event on the basis that the appropriate method to mitigate against the risk of a retailer failure event is through the prudential requirements contained in clause 6.21.1 of the Rules.

However, it not possible for Victorian DNSPs to do this because they are constrained by their distribution licences to implement the default Use of Systems Agreement (UoSA) provisions which reflect the credit support arrangements in the ESC's decision on credit support of 1 October 2006 (ESC Credit Decision). These credit support arrangements do not fully compensate distributors for retailer failure.

These credit support arrangements were put in place on the basis that Victorian DNSPs had a pass through event for a financial failure of a retailer event. If the AER wants to reject the financial failure of a retailer as a pass through event, the AER will have to amend the credit support arrangements under the default UoSA to give distributors full credit support. If not, it should grant the pass through event.

The specification of a retailer failure event as a nominated pass through event is consistent with the requirements of the NEL and Rules and should be accepted by the AER. The inclusion of this event will help to ensure that UED is provided with a reasonable opportunity to recover its efficient costs, and has effective incentives in order to promote economic efficiency.

19.3.5 Transmission related costs pass through event

UED has proposed that the AER should include a new term in each of the WAPC and side constraint formulas to address transmission related costs.

In the event that the AER rejects its proposed control mechanism changes the AER must include a nominated pass through event in its Final Distribution Determination in respect of these costs.

It is worth noting that UED is of the view that the transmission related costs nevertheless are recoverable. Having further considered clause 6.18.2 and 6.18.7 of the NER UED remains of the view that a Rule change is desirable, however, considers that absent that Rule change transmission related costs are recoverable at the pricing proposal stage.

Whilst the definitions that are used in chapter 5 suggest a distinction between use services and connection services (see prescribed transmission service, shared transmission service and connection service) the relevant definition for clause 6.18.7 purposes is 'transmission use of system [service]' which is (relevantly) a 'customer transmission use of system service' which in turn is "a service provided to a Transmission Network User for use of the 'transmission network' for the conveyance of electricity..."

The term used in clause 6.18.7 is 'transmission use of system [service]' and not 'shared transmission service' and, in that context and with the requirements of the revenue and pricing principles in mind, 'a service provided for the use of the transmission network' in clause 6.18.7 includes connection - you can't use the transmission network if you're not connected to it. A shared transmission service is distinct from a connection service in chapter 5 but those are not the relevant terms for clause 6.18.7.

In addition, whilst clause 6.18.7 requires the pricing proposal to provide for transmission use of system service charges, that is a requirement which only goes to the content of UED's proposal and it does not constrain that content. Clause 6.18.7 is an obligation to include in the pricing proposal tariffs to pass on transmission use of system charges. But it does not limit the pricing proposal to transmission use of system charges. The pricing proposal clearly deals with a broader range of matters and can include tariffs designed to pass on other charges as long as they relate to direct control services.

Moreover, clause 6.18.7 does not go to the scope of the AER's discretion. That is dealt with in clause 6.18.8 which relevantly requires only that the forecasts associated with the proposal be reasonable as Part I and the distribution determination will not otherwise be the subject of compliance.

The only constraint is in 6.18.1 is the tariffs must relate to 'direct control services'.

The transmission connection charge relates to a distribution service (it allows for the conveyance of electricity through the distribution system) just like the transmission use of system service charge which is recognised as relating to a direct control service in clause 6.18.

Similarly, PFIT rebates relate to a distribution service; as the AER recognises PFIT schemes can be considered as embedded generators under the NER.

UED agrees with the AER that inter-DNSP payments are not related to the use of the transmission network. However that's not the correct test; the correct test is whether they relate to a distribution service which they clearly do as they too allow the conveyance of electricity through the distribution system.

UED also agrees that avoided DUOS and TUOS are not related to the use of the transmission network. However that's not the correct test; the correct test is whether they relate to a distribution service which they clearly do as the Rule itself recognises transmission use of system charges (and so avoided transmission use of system charges) and avoided DUOS self evidently relates to the distribution system.

When submitting its pricing proposal UED will include tariffs related to:

- Transmission connection charges;
- PFIT charges
- Inter- DNSP payments; and
- Avoided TUOS and DUOS.

Nevertheless, if the AER disagrees with UED's interpretation of the Rules, section 7A(2) of the NEL, and the requirement that UED must be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services, means

The 'transmission related costs event' should cover the difference between forecast and actual expenditure in respect of PFIT payments, transmission connection charges, inter-DNSP charges and avoided TUOS and avoided DUOS payments.

The inclusion of this event as a nominated pass through is consistent with the NEL and the Rules as it will provide UED with a reasonable opportunity to recover its efficient costs.

Further, this event satisfies the AER's criteria for nominated pass through events:

- it is foreseeable in that it can be identified in advance;
- it is potentially of high magnitude;
- it is beyond the control of DNSPs;
- the event cannot be self-insured;
- the party who is in the best position to manage the risk is bearing the risk; and
- the pass through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

UED proposes that this pass through event would be defined as follows:

> **A transmission pass through event** means any application or interpretation of the Rules under which UED is unable to recover actual transmission connection (exit) charges, actual costs incurred under Division 5A of Part 2 of the Electricity Industry Act (Vic), actual inter-DNSP payment costs and actual avoided TUOS and avoided DUOS payments.

19.3.6 Electrical safety management scheme event

Electricity Safety Management Scheme event under the Electricity Safety Act 1998, ESV may provisionally accept an ESMS if it is satisfied that it will provide for the safe operation of the supply network. In respect of such a provisional acceptance ESV may impose any limitations or conditions that will apply in respect of the design, construction, operation, maintenance or decommissioning of the supply network while the provisional acceptance is in force.

Conditions or limitations which ESV imposes on a provisional acceptance of an ESMS have the potential to materially increase UED's costs of providing direct control services. Accordingly, UED proposes that there be a nominated pass through event for such conditions or limitations.

The inclusion of this event as a nominated pass through is consistent with the NEL and the Rules as it will provide UED with a reasonable opportunity to recover its efficient costs and with effective incentives in order to promote economic efficiency

Further, this event satisfies the AER's criteria for nominated pass through events:

- it is foreseeable in that it can be identified in advance;
- it is potentially of high magnitude;
- it is beyond the control of DNSPs;
- the event cannot be self-insured;
- the party who is in the best position to manage the risk is bearing the risk; and
- the pass through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

UED proposes that this pass through event would be defined as follows:

An electricity safety management scheme event means an event which relates to the imposition by ESV of conditions or limitations in respect of the design, construction, operation, maintenance or decommissioning of the supply network on its provisional acceptance of an electricity safety management scheme under section 103 of the *Electricity Safety Act* 1998.

19.3.7 Conclusion

While UED has chosen to remove specific nominated pass through events for corporate income tax assumptions, vegetation management clearance and force majeure, its Regulatory Proposal in respect of pass through events is otherwise that set out in its Initial Regulatory Proposal. Moreover, UED seeks the pass through events nominated by the AER and a transmission pass through event and an electricity safety management scheme event.

19.4 UED's response to the AER's draft determination on materiality

In its Draft Determination, the AER moved away from its approach to defining materiality which it had very recently applied in the Queensland and South Australian distribution determinations and also applied in the NSW and ACT distribution determinations.

Previously it had been the AER's view that a different materiality threshold should apply to specific and general nominated pass through events, with specific nominated pass through events having a materiality threshold of the administrative costs of assessing the application, whereas only general nominated pass through events should have a materiality threshold of 1 per cent of a DNSP's annual forecast revenue.

The AER's draft determination was that:

> "…the appropriate materiality threshold for all pass through events for the Victorian DNSPs is one per cent of the smoothed forecast revenue in each of the years of the regulatory control period." (DD, p.715)

UED rejects this draft position on several grounds.

19.4.1 Failure to comply with the Rules

The Rules establish the meaning to be given to "materially" in the context of the pass through provisions, and clearly draw a distinction between transmission and distribution in this regard.

Specifically, chapter 10 of the Rules defines "materially" as:

- in the context of transmission pass throughs in clause 6A.7.3, 1 per cent of the maximum allowed revenue for the transmission network service provider for the regulatory year; and
- in other contexts, the word has its ordinary meaning.

Therefore, the AER's assessment of whether a pass through event is material must involve the objective application of the ordinary meaning of 'material'.

Clause 6.2.8(a)(4) of the Rules enables the AER to publish guidelines as to the AER's likely approach to determining materiality in the context of possible pass through events. However, the AER has not published any such guidelines. Even so, and regardless of any guidance the AER provides on its general approach to assessing materiality whether in a distribution determination or guidelines under clause 6.2.8(a)(4), the AER is obliged to apply the ordinary meaning of 'material'. Neither the guidelines nor a distribution determination can change the meaning of 'material' in the Rules.

Moreover, to align the materiality threshold with the definition of 'positive change event' given in Chapter 10 of the Rules requires the AER to apply the ordinary meaning of 'material' on a case by case basis. Each such event needs to be assessed against that threshold when it arises.

The AER has also explained its preference for the 1 per cent materiality threshold in terms of a desire to maintain consistency between its determination in respect of Victorian DNSPs and its approach to transmission regulation. Under the Rules, the materiality threshold for transmission cost pass throughs is prescribed as 1 per cent of the TNSP's maximum allowed revenue. The AER has stated that:

> "…without a good reason for differences, consistency between transmission and distribution regulation is desirable." (DD, p.715)

The AER has chosen not to acknowledge that the Rules prescribe a different meaning of 'materially' to distribution pass throughs than to transmission pass throughs. If it was intended that distribution pass throughs were to have the same materiality threshold as distribution pass throughs surely the definition of 'materially' in Chapter 10 of the Rules would reflect this.

In fact, the distinction contained in the Rules is consistent with materiality in distribution most likely being lower than materiality in transmission.

19.4.2 Failure to meet national electricity objectives

UED considers that imposing a quantitative materiality threshold with regard to specific pass through events is inconsistent with the requirements of section 7A(2) of the NEL which states that:

> "A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment."

For the AER to refuse to allow UED to recoup a material cost just because it is below a 1 per cent threshold – being a cost which UED cannot mitigate – places UED in a position where it cannot recover a cost which will inevitably be incurred by a prudent service provider acting efficiently.

For example, costs may or may not meet the threshold based solely on their timing relative to the beginning/end of the regulatory year. If the costs are incurred over June/July, for example, there is less likelihood they will meet the threshold than if incurred over December/January. There is no rationale for such an outcome. The fact that the costs are incurred over June/July rather than December/January does not mean UED is more capable of managing those costs.

It is also conceivable that two events below the 1 per cent threshold could occur in any one year. For example, two events each equivalent to 0.9 per cent of the threshold could occur with no pass through allowed. This implies that the AER considers, for example, that an impost equivalent to 1.8 per cent of revenue is also not material.

Finally, if the draft determination was implemented and one event per year eventuated just below the 1 per cent threshold, it would be possible for UED to lose up to $14 million of revenue over the coming regulatory control period (this represents almost 1 per cent of UED's annual revenue requirement as calculated by the AER in the draft determination summed across the five years). Such an amount cannot be considered by a reasonable person to constitute an immaterial amount.

To deny UED the opportunity to earn up to 1 per cent of the required revenue equates to the AER approving a lower rate of return than that recommended in the draft determination.

As imposts are beyond UED's control they cannot be avoided. There is therefore no way for UED to eliminate this cost. Requiring UED to bear a certain portion of impost costs will not provide any incentive to UED to reduce those imposts costs (as this cannot, by definition, be achieved). Further, as noted above, requiring UED to incur costs it cannot recoup reduces the funds otherwise available to UED to invest in development of its network.

The materiality threshold will prevent UED recovering all efficient costs incurred in delivering regulated network services. As imposts are beyond UED's control, there can be no argument that they are not efficient. The AER does not explain how UED is to recover the resultant shortfall. Unless the AER systematically over-forecasts capital and opex, then UED cannot be expected to over-recover as a result of those forecasts and it is unclear how UED is to recover those otherwise unrecovered uncontrollable costs. In the longer term this may undermine the viability of all Victorian DNSPs and their capacity to invest.

19.4.3 Increasing risk without compensation

Under section 7A(5) of the NEL:

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

The AER's materiality threshold would result in an increase in regulatory and commercial risks facing UED.

Under the ESCV's 2006-10 EDPR, the materiality threshold is not quantified and stated simply in terms of a pass through event having a 'material financial impact on the distribution business'. Currently, 'material' is not defined and, accordingly, it takes its ordinary meaning. This is a lower threshold than the AER's proposed threshold of 1 per cent of smoothed forecast revenue.

The pass through mechanism is intended to lower risk faced by DNSPs which would otherwise have to be compensated for in the calculation of regulated revenues. A corollary is that any watering down of the application of the pass through mechanism must be offset by higher prices or charges.

As the AER's draft determination proposes a higher materiality threshold for pass through events than is currently imposed by the ESCV's 2006-10 EDPR, an increase in allowed revenues would be justified if the AER's determination was to replace the ESCV's 2006-10 EDPR. However, the AER is not proposing to provide any compensation to the DNSPs for carrying this additional risk, nor has it allowed any additional expenditure through self insurance or opex because both of these are based on revealed 2009 costs. Nor has the AER amended its calculation of WACC to allow a premium for managing the additional risk.

19.4.4 Conclusion

The materiality threshold for specific nominated pass through events should continue to be that the event is 'material' within its ordinary meaning. This is consistent with the definition of a 'positive change event' and 'negative change event' in the Rules, and of 'materially' in Chapter 10 of the Rules which provides that outside of clause 6A.7.3, 'materially' has its ordinary meaning.

There is no reason to believe that such a threshold would not achieve the purpose of a materiality provision as identified by the AER namely:

"…to reduce the administrative burden of excessive applications for pass through events, while still including events which may materially affect the business." (DD, p.715)

19.5 UED's Revised Regulatory Proposal on pass through events

UED has reviewed all of the matters raised by the AER in its Draft Determination. UED has prepared this Revised Regulatory Proposal to be consistent with the Draft Determination, with the exception of the following deviations.

Specifically, UED has revised its Regulatory Proposal to:

- remove specific nominated pass through events for corporate income tax assumptions, vegetation management clearance and force majeure as proposed in its original Regulatory Proposal;
- include specific nominated pass through events for:
  - a natural disaster event
  - an insurance event/legal liability above insurance cap event;
  - an insurer credit risk event;
  - transmission connection fees, inter DNSP fees and PFIT recovery; and
  - conditions or limitations imposed by ESV on provisional acceptance of an ESMS under the Electricity Safety Act 1998;
- have a materiality threshold for nominated pass through events that the event has a material financial impact on the distribution business, with material being interpreted according to its ordinary meaning.

UED's Revised Regulatory Proposal in respect of pass throughs is otherwise as set out in its original Regulatory Proposal.

20. Negotiating framework

Key messages

UED's original Regulatory Proposal explained that UED's proposed negotiating framework is consistent with the requirements of clause of the Rules.

The AER's Draft Decision accepted UED's proposed negotiating framework subject to clause 8(b) of the negotiating framework being amended to remove the words "take reasonable steps".

UED will implement the amendment to clause 8(b) of its negotiating framework, in accordance with the requirements of the Draft Decision.

20.1 Recap on UED's Regulatory Proposal

UED's original Regulatory Proposal explained that clause 6.7.5 of the Rules requires that UED must prepare a document (the negotiating framework) setting out the procedure to be followed during negotiations between UED and any person (the Service Applicant or applicant) who wishes to receive a negotiated distribution service from UED, as to the terms and conditions of access for the provision of the service.

UED explained that its negotiating framework has been prepared having regard to:

- the requirements of clause 6.7 of the Rules in relation to negotiated distribution services; and
- UED's existing processes for negotiating the provision of customer connection and augmentation works.

UED demonstrated that its proposed negotiating framework satisfied the requirements fo the Rules.

20.2 AER's Draft Decision on UED's negotiating framework

In accordance with clause 6.12.3(g) of the Rules, the Draft Decision did not approve the negotiating framework proposed by UED, as the AER found that it did not fully comply with the requirements of clause 6.7.5 of the Rules.

The AER's reasons for not approving UED's negotiating framework are as set out on page 46 as follows:

> Clause 8(b) of United Energy's negotiating framework states that 'United Energy must notify and consult with any affected distribution network users and take reasonable steps to ensure that the provision of the negotiated distribution service does not result in non compliance with obligations to other distribution network users'. In order to maintain consistency with clause 6.7.5(c)(9) of the NER, the AER considers this should be amended by removing the words 'take reasonable steps'. This will also ensure that responsibility for maintaining compliance with NER obligations for other network users remains with the DNSP.

20.3 UED’s response to the AER’s Draft Decision on UED’s negotiating framework

UED will implement the amendment to clause 8(b) of its negotiating framework, in accordance with the requirements of the Draft Decision (noted above).

21. Alternative Control Services

Key messages

- UED provided a comprehensive list and prices of alternative control services as part of its original proposal
- UED based its prising on the prices received from the tender prices and the now approved CAM
- UED has provided the draft decision to the winning bidder to confirm pricing arrangements
- Based on updated advice received from the winning bidder UED has updated those prices where there has been a change

21.1 Recap on UED's Regulatory Proposal

UED's regulatory proposal provided a detailed appendix (C-2) that included a description of services and a pricing schedule. UED did not provide a schedule of hourly rates or terms of supply to be approved for quoted services – these are now provided in this revised proposal.

21.2 AER's draft determination on UED's alternative control services

The AER says that it has been unable to undertake a revealed cost approach to reviewing United Energy's prices. Instead they have relied on benchmarking proposed prices against a reasonable range. The AER has also accepted UED's price control formula and rejected a number of proposed prices on the basis that UED has arbitrarily inflated the rates.

21.3 UED's response to the AER's draft determination on UED's alternative control services

UED is pleased to note the AER's acceptance of the price control formula. This formula ensures that prices during the period will be at least in line with inflation and will provide a revenue stream that matches the costs to UED.

The AER has rejected the pricing for meter data services proposed by UED. UED's submission is clearly marked that the prices are only for those customers who consumers who consume greater than 160 MWh. These customers are not included in the AMI OIC. The AER incorrectly assumes that these services are for all meters whereas UED's submission is clearly marked as those meters to customers that consume greater than 160MWhs. These customers are not included in the AMI OIC and therefore a pricing mechanism is required in order to recover these costs.

UED concedes that it applied prices arbitrarily for some services. These prices have been reviewed by the winning tender. They have provided updated rates to reflect the service being provided. The table below provides a comparison

Table 21-1: Revised Alternative Control Rervices Prices

Alternative Control Services	Original Prices 2011 – 2015 (in $2010)	Revised Prices
Field Officer Visits – Existing Premises		
Special read (basic meter)	9.97	9.97
Special read (interval meter)	11.07	11.07
Re-energise (fuse insert) – normal hours (unit rate)	35.91	35.91
De-energise (fuse removal) – normal house (unit rate)	35.91	35.91
Express move in re-energise (fuse insert) – normal hours (unit rate)	108.21	108.21
Re-energise (fuse insert) – after hours (unit rate)	114.77	114.77
De-energise (fuse removal) – after hours (unit rate)	114.77	114.77
Express move in re-energise (fuse insert) – after hours (unit rate)	114.77	114.77
Temporary Supplies (exc inspection) – Coincident Disconnection		
Standard single phase, normal hours (unit rate)	83.97	83.97
Multi phase to 100A, normal hours (unit rate)	239.00	83.97
Standard single phase, after hours (unit rate)	176.96	176.96
Multi phase to 100A, after hours (unit rate)	503.71	317.19
Temporary Supplies (exc inspection) – Independent Disconnection		
Independent disconnection standard single phase, normal hours (unit rate)	167.93	167.93
Independent disconnection multi phase to 100A, normal hours (unit rate)	401.15	333.66
Independent disconnection standard single phase, after hours (unit rate)	353.91	353.91
Independent disconnection multi phase to 100A, after hours (unit rate)	845.41	845.41
Conversion from Coincidental to Independent Disconnection		
Standard single phase – changed from coincidental to independent (unit rate)	83.96	83.96
Multi Phase – changed from coincidental to independent (unit rate)	176.96	176.96

Alternative Control Services	Original Prices 2011 – 2015 (in $2010)	Revised Prices
New Connection where UED is the Responsible Person		
Single phase single element – normal hours (unit rate)	201.38	201.38
Single phase two element (off-peak) – normal hours (unit rate)	201.38	201.38
Three phase direct connected – normal hours (unit rate)	201.38	201.38
Single phase single element – after hours (unit rate)	452.15	261.35
Single phase two element (off-peak) – after hours (unit rate)	452.15	317.19
Three phase direct connected – normal hours (unit rate)	659.01	358.21
Three phase current transformer connected – normal hours (unit rate)	Not provided	967.47
Three phase current transformer connected – after hours (unit rate)	Not provided	1038.59
New Connections – where UED is Not the Responsible Person		
Single phase single element – normal hours (unit rate)	87.51	87.51
Single phase two element (off-peak) – normal hours (unit rate)	87.51	87.51
Three phase direct connected – normal hours (unit rate)	87.51	87.51
Single phase single element – after hours (unit rate)	175.02	249.56
Single phase two element (off-peak) – after hours (unit rate)	175.02	325.19
Three phase direct connected – after hours (unit rate)	175.02	367.21
Three phase current transformer connected – normal hours (unit rate)		953.66
Three phase current transformer connected – after hours (unit rate)		
Service Vehicle Visits (without inspection)		
Service truck – first 30 minutes – normal hours (unit rate)	102.16	102.16

Alternative Control Services	Original Prices 2011 – 2015 (in $2010)	Revised Prices
Each additional 15 minutes – normal hours (unit rate)	41.98	41.98
Wasted service truck visit – normal hours (unit rate)	41.98	41.98
Service truck – first 30 minutes – after hours (unit rate)	158.49	208.44
Each additional 15 minutes – after hours (unit rate)	44.95	44.95
Wasted service truck visit – after hours (unit rate)	158.49	103.95
Meter Equipment Test		
Single phase	49.83	49.83
Single phase (each additional meter)	44.29	44.29
Multi phase	77.51	77.51
Multi phase (each additional meter)	71.97	71.97
Meter Provision Charges (Manually Read) >160 MWh		
Three phase direct connected meter – 1st tier (unit rate)	193.12	193.12
Three phase current transformer connected meter – 1st tier (unit rate)	412.34	412.34
Meter Data Services >160 MWh		
Quarterly read meter	37.58	37.58
Monthly read meter	112.74	112.74

Quoted services below

Table 21-2: List of quoted services

	Original Proposal	Revised Proposal
Temporary Cover of LV Mains		
Service cable – per span – normal hours (unit rate)	162.14	Quoted see labour rates below
Service cable – per span – after hours (Unit rate)	522.88	Quoted see labour rates below
Services monthly rental	5.22	Quoted see labour rates below

LV mains two wire cover – normal hours (unit rate)	362.28	Quoted see labour rates below
LV mains two wire cover – after hours (unit rate)	622.88	Quoted see labour rates below
Two wire monthly rental	22.97	Quoted see labour rates below
LV mains all wire cover – per span – normal hours (unit rate)	623.14	Quoted see labour rates below
LV mains all wire cover – per span – after hours (unit rate)	697.99	Quoted see labour rates below
All wire monthly rental	57.41	Quoted see labour rates below
Possum guard fitted to service line	205.32	Quoted see labour rates below
Elective Underground Servicing		
New installation, single phase, 80A up to 5m length – normal hours (unit rate)	603.40	Quoted see labour rates below
New installation, multi phase to 100A up to 5m length – normal hours (unit rate)	711.18	Quoted see labour rates below
New installation, multi phase to 170A up to 5m length – normal hours (unit rate)	1,319.10	Quoted see labour rates below
Existing installation, single phase, 80A up to 5m length – normal hours (unit rate)	834.93	Quoted see labour rates below
Existing installation, multi phase to 100A up to 5m length – normal hours (unit rate)	942.71	Quoted see labour rates below
Existing installation, multi phase to 170a up to 5m length – normal hours (unit rate)	1,822.29	Quoted see labour rates below
New installation, single phase, 80A up to 5m length – after hours (unit rate)	Recoverable works	Quoted see labour rates below
New installation, multi phase to 100A up to 5m length – after hours (unit rate)	Recoverable works	Quoted see labour rates below
New installation, multi phase to 170A up to 5m length – after hours (unit rate)	Recoverable works	Quoted see labour rates below
Existing installation, single phase, 80A up to 5m length – after hours (unit rate)	Recoverable works	Quoted see labour rates below
Existing installation, multi phase to 100A up to 5m length – after hours (unit rate)	Recoverable works	Quoted see labour rates below
Existing installation, multi phase to 170A up to 5m length – after hours (unit rate)	Recoverable works	Quoted see labour rates below
Additional material – single phase, 80A each additional metre (unit rate)	39.86	At cost
Additional material – single phase, 100A each additional metre (unit rate)	39.86	At cost

Additional material – multi phase, 170A each additional metre (unit rate)	49.83	At cost
Service Cable Pulled Down by High Loads		
Single phase, aluminium service cable – normal hours (unit rate)	212.94	Quoted see labour rates below
Multi phase, aluminium service cable – normal hours (unit rate)	263.44	Quoted see labour rates below
Single phase, copper service cable – normal hours (unit rate)	237.40	Quoted see labour rates below
Multi phase, copper service cable – normal hours (unit rate)	355.83	Quoted see labour rates below
Single phase, aluminium service cable – after hours (unit rate)	441.11	Quoted see labour rates below
Multi phase, aluminium service cable – after hours (unit rate)	491.60	Quoted see labour rates below
Single phase, copper service cable – after hours (unit rate)	465.57	Quoted see labour rates below
Multi phase, copper service cable – after hours (unit rate)	544.41	Quoted see labour rates below
Miscellaneous Services		
Security lighting installation fee	613.57	Quoted see labour rates below

UED has had discussions with the winning bidder. They have provided the rates in response to a request from UED. These are provided in the table below:

Table 21-3: Proposed hourly rates to apply for quoted services

Description	Proposal	Revised Proposal
Hourly Rate for one person (BH)	Not provided	$79.80
Hourly Rate for one person + vehicle (BH)	Not provided	$108.90
Hourly Rate for one person (AH)	Not provided	$99.75
Hourly Rate for one person + vehicle (AH)	Not provided	$121.56

These hourly rates will be applied to all quoted services listed in the AER draft decision.

The AER has accepted the prices for other aspects of the tender process and therefore should accept these hourly rates as being part of the market competitive bid process. These hourly rates are the subject of a market completive bid as opposed to a theoretical benchmarking exercise of rates.

22. Public lighting

Key messages

- UED provided a public lighting prices using the AER's model
- UED based its pricing on the assumptions contained in that model
- The AER did not accept the recovery of 2009 and 2010 expenditure in one year and instead smoothed the recovery over 5 years
- The AER applied an updated labour and material escalator to UED's pricing

22.1 Recap on UED's Regulatory Proposal

UED's public lighting model was consistent wit the AER model provided in November 2009. UED provided actual forecast in the current regulatory period (based on annual regulatory accounts) and forecast capital expenditure based on a detailed asset management plan.

UED also based its public lighting proposal on a limited building block approach consistent with the AER methodology.

22.2 AER's draft determination on UED's public lighting pricing

The AER has generally accepted UED's approach to pricing with the exception of the following items:

- The escalation on labour rates to be consistent with the AER's decision on labour escalation for standard control services
- Recovery of captal spent in 2009 and 2010 to be spread over 5 years rather than one year
- Failure rate for MV80 lighting changed from 37.5 per cent to 19.6 per cent

22.3 UED's response to the AER's draft determination on UED's public lighting

UED accepts the AER's draft decision on public lighting and notes that the model should be updated to reflect the labour and material escalators to be determined by the AER in its final decision. UED has attached the public lighting model as part of this proposal including the labour rate escalators described earlier in this submission.

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APPENDICES

Ref	Title	Status
A-1	Directors' Certification of Key Assumptions	Public
A-2	CEO's Statutory Declaration	Public
A-3	Regulatory Information Notice – Proforma Statements	Commercial in Confidence
B-1	Post Tax Revenue Model	Public
B-2	Roll Forward Model	Public
B-3	Public Lighting Model	Public
B-4	Capital Expenditure Forecast	Commercial in Confidence
B-5	Line Clearance	Public
B-6	Line Clearance Costings	Public
B-7	Line Clearance Examples	Public
B-8	Capex trf reconciliation	Commercial in Confidence
C-1	NIEIR	Public
C-2	BIS Wages Outlook	Public
C-3	BIS AE Model Review	Public
C-4	ATK Report	Commercial in Confidence
C-5	FSA - KPMG Review	Commercial in Confidence
C-6	FSA	Commercial in Confidence
C-7	AECOM Review	Public
C-8	Deloitte Review	Public
C-9	Ferrier Hodgson Report	Commercial in Confidence
C-10	Probity advice	Commercial in Confidence
C-11	DUET Costs 2009	Commercial in Confidence
C-12	KPMG report of DUET services	Commercial in Confidence
C-13	KPMG report re Bases of Opex	Public
C-14	AECOM Climate update	Public
C-15	SAP Update	Commercial in Confidence
C-16	Derivation of base year costs	Commercial in Confidence
C-17	NIEIR Maximun Demand	Public
C-18	ZSS NIEIR reconciliation	Public
C-19	NIEIR Maximun Demand	Public
D-1	Aerial Bundled Conductor in UED High Bushfire Risk Areas	Commercial in Confidence

Ref	Title	Status
D-2	Aerial Bundled Conductor in UED High Bushfire Rosk Areas	Commercial in Confidence
D-3	Air-Conditioning of Control Rooms	Commercial in Confidence
D-4	Automatic Recloser (ARC) & Remote Control Gas Switches	Commercial in Confidence
D-5	Box Hill (BH) zone substation capacity constraint	Commercial in Confidence
D-6	Distribution Transformer Replacement Program	Commercial in Confidence
D-7	Dromana (DMA) zone substation capacity constraint	Commercial in Confidence
D-8	Increasing Data Centre Fibre Capacity	Commercial in Confidence
D-9	Keysborough (KBH) new zone substation	Commercial in Confidence
D-10	Langwarrin (LWN) zone substation capacity constraint	Commercial in Confidence
D-11	Lyndale (LD) zone substation capacity constraint	Commercial in Confidence
D-12	Mentone (M) zone substation capacity constraint	Commercial in Confidence
D-13	Overhead Conductor Replacement Program	Commercial in Confidence
D-14	Pole Mounted Capacitor Banks	Commercial in Confidence
D-15	Pole Replacement Program	Commercial in Confidence
D-16	Pole Top Structure Replacement Program	Commercial in Confidence
D-17	Reactive Fault Mitigation	Commercial in Confidence
D-18	Templestowe (TSE) new zone substation	Commercial in Confidence
D-19	2010 - GFN & SWER	Commercial in Confidence
D-20	2010 Power Quality	Commercial in Confidence
D-21	Neutral Screened Services	Commercial in Confidence
D-22	Pole Top Fire Mitigation	Commercial in Confidence
D-23	Public Lighting Switch Wire Removal	Commercial in Confidence
D-24	Supervisory Cable Replacement Programme 2010-2015	Commercial in Confidence
D-25	Underground Cable Systems Replacement Program	Commercial in Confidence
D-26	Zone Substation Back-Up Earth Fault Protection	Commercial in Confidence
D-27	Zone Substation Circuit Breaker Replacement Program	Commercial in Confidence
D-28	Zone Substation Transformer Replacements	Commercial in Confidence
D-29	TBTS - DMA - RBD - STO Reinforcement	Commercial in Confidence
D-30	Springvale-Springvale West (SV-SVW) zone substations capacity contraint	Commercial in Confidence
D-31	DA Over AMI Strategic Planning Paper	Commercial in Confidence
D-32	Exploding asset	Public
D-33	Failed Kiosk	Public
D-34	Kiosk Failure2	Public
D-35	Failed Transformer Photos	Public

Ref	Title	Status
D-36	House fire	Public
D-37	House fire 2	Public

F-1	Hathaway (2010g1). Comment on: "A Measure of the Efficacy of the Australian Imputation Tax System" by John Handley and Krishan Maheswaran. A report prepared by Neville Hathaway, Capital Research, July 2010.	Public
F-2	Hathaway (2010g2). Imputation Credit Redemption: ATO data 1988-2008. Prepared by Neville Hathaway, Capital Research, July 2010.	Public
F-3	Hathaway (2010g3). Practical Issues in the AER Draft Determination. Prepared by Neville Hathaway, Capital Research, July 2010.	Public
F-4	Officer R.R. and S.R. Bishop (2010g). Market Risk Premium: Comments on the AER Draft Distribution Determination for Victorian Electricity Distribution Network Service Providers, July 2010. A report by Professor Bob Officer and Dr Steven Bishop, Value Adviser Associates Pty. Ltd.	Public
F-5	CEG (2010g). Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates. A Report for Victorian Electricity DBs. Prepared by Tom Hird, Competition Economists Group, July 2010.	Public
F-6	PwC (2010g). Methodology for calculating the debt risk premium. Letter to Mark de Villiers, Citipower and Powercor. Prepared by Jeff Balchin and Matthew Santoro, PricewaterhouseCoopers, 19th July 2010.	Public
F-7	SFG (2010g). Issues relating to the estimation of gamma. A report prepared for Citipower, Jemena Electricity Networks, Powercor, SP-Ausnet, and United Energy Distribution, Strategic Finance Group (SFG Consulting),15th July 2010.	Public
F-8	Beggs and Skeels (2006). Market Arbitrage of Cash Dividends and Franking Credits, David J. Beggs and Christopher L. Skeels. The Economic Record, Volume 82, Number 258, pages 239-252, September 2006.	Journal article not to be published
F-9	Feros (2009f). Review of WACC parameters: Gamma. Prepared for the ETSA Price Reset by Peter Feros, tax partner, Gilbert and Tobin lawyers, Sydney, 22nd June 2009.	Public
F-10	Handley (2009d). Report Prepared for the Australian Energy Regulator. Further Comments on the Valuation of Imputation Credits, Associate Professor John Handley, 15th April 2009.	Public
F-11	Handley (2009j). Memorandum Prepared for the Australian Energy Regulator. Advice on Gamma in Relation to the 2010-2015 Qld/SA Electricity Distribution Determinations, Associate Professor John Handley, 20th October 2009.	Public
F-12	Handley (2010c). Report prepared for the AER on the estimation of gamma, Associate Professor John Handley, 19th March 2010.	Public

Ref	Title	Status
F-13	Handley and Maheswaran (2008c). A Measure of the Efficacy of the Australian Imputation Tax System, John C. Handley and Krishnan Maheswaran, March 2008. The Economic Record, Volume 84, Number 264, March 2008, pages 82-94.	Journal article not to be published
F-14	Hathaway and Officer (2004k). The Value of Imputation Tax Credits, Update 2004. Neville Hathaway and Bob Officer, Capital Research Pty. Ltd., 2nd November 2004.	Public
F-15	Lally M. (2000). Valuation of companies and projects under differential personal taxation, Pacific-Basin Financial Journal, volume 8, Number 1, March 2000, pages 115–133.	Journal article not to be published
F-16	Lally M. (2002). The cost of capital under dividend imputation. Prepared for the Australian Competition and Consumer Commission by Associate Professor Martin Lally, School of Economics and Finance, Victoria University of Wellington, June 2002.	Public
F-17	McKenzie and Partington (2010c). Evidence and submissions on gamma, Professor Michael McKenzie and Associated Professor Graham Partington, 25th March 2010.	Public
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F-19	NERA (2010a). Payout Ratio of Regulated Firms. A report for Gilbert and Tobin by NERA Economic Consulting, 5th January 2010.	Public
F-20	Officer, R. (1994). The cost of capital under an imputation tax system, R.R. Officer, Accounting and Finance, volume 34, Number 1, pages 1–36.	Journal article not to be published
F-21	Officer R.R. (2009f). Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers, R.R. Officer, 22nd June 2009.	Public
F-22	Officer R.R. and S.R. Bishop (2009a). Market Risk Premium: Further Comments. Value Adviser Associates, January 2009.	Public
F-23	Officer R.R. and S.R. Bishop (2009j). Market Risk Premium: Estimate for 2011-2015, October 2009. A report by Professor Bob Officer and Dr Steven Bishop, Value Adviser Associates Pty. Ltd.	Public
F-24	CEG (2009). Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008. Prepared by Tom Hird, Competition Economists Group, September 2009.	Public
F-25	CEG (2010a). Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates. A Report for Country Energy. Prepared by Tom Hird, Competition Economists Group, January 2010.	Public

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F-26	PwC (2009k). Victorian Distribution Businesses. Methodology to Estimate the Debt Premium. Prepared by Jeff Balchin and Matthew Santoro, PricewaterhouseCoopers, November 2010.	Public
F-27	PwC (2010c). Jemena Gas Networks (NSW). The cost of debt for a gas distributor. Prepared by Jeff Balchin, PricewaterhouseCoopers, March 2010.	Public
F-28	PwC (2010d). Update of cost of debt methodology analysis in light of the AER's ActewAGL decision. Prepared by Jeff Balchin and Matthew Santoro, PricewaterhouseCoopers, 28th April 2010.	Public
F-29	SFG (2008). The impact of franking credits on the cost of capital of Australian firms. Report prepared for ENA, APIA and Grid Australia. Strategic Finance Group, 16th September 2008.	Public
F-30	SFG (2009b). The value of imputation credits as implied by the methodology of Beggs and Skeels (2006). Prepared by the Strategic Finance Group, 1st February 2009.	Public
F-31	SFG (2009b3). The consistency of estimates of the value of cash dividends. Report prepared for ENA, APIA, and Grid Australia. Strategic Finance Group, 1st February 2009.	Public
F-32	SFG (2009b2). Market practice in relation to franking credits and WACC: Response to AER proposed revision of WACC parameters. Report prepared for ENA, APIA, and Grid Australia. Strategic Finance Group, 1st February 2009.	Public
F-33	SFG (2009b2). Market practice in relation to franking credits and WACC: Response to AER proposed revision of WACC parameters. Report prepared for ENA, APIA, and Grid Australia. Strategic Finance Group, 1st February 2009.	Public
F-34	NERA (2010e). New Gamma Issues Raised by AER Expert Consultants. A Report for JGN. Prepared by NERA Economic Consulting, Sydney, 17th May 2010.	Public
F-35	SFG (2010b). Further analysis in response to AER Draft Determination in relation to gamma. A report prepared for ETSA Utilities by the Strategic Finance Group (SFG Consulting), 4th February 2010.	Public
F-36	Skeels (2009h). A Review of the SFG Dividend Drop-Off Study. A Report prepared for Gilbert and Tobin by Christopher L. Skeels, Department of Economics, The University of Melbourne, 28th August 2009.	Public
F-37	Skeels (2009i). Response to AER Questions. A Report prepared for ETSA Utilities by Christopher L. Skeels, Department of Economics, The University of Melbourne, 21st September 2009.	Public
F-38	Skeels (2009f). Estimation of Gamma. A Report prepared for ETSA Utilities by Christopher L. Skeels, Department of Economics, The University of Melbourne, 18th June 2009.	Public

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F-39	Skeels (2010a). Response to Australian Energy Regulator Draft Determination. A Report prepared for Gilbert and Tobin by Christopher L. Skeels, Department of Economics, The University of Melbourne, 13th January 2010.	Public
F-40	Synergies (2009e). Synergies (May 2009) Gamma: New Analysis Using Tax Statistics. Prepared for ENERGEX and Ergon Energy by Synergies Economic Consulting, 28th May 2009.	Public
F-41	Monkhouse P (1993). The cost of equity under the Australian dividend imputation tax system, Peter Monkhouse. Accounting and Finance, 33, pages 1-18.	Journal article not to be published
F-42	Truong G., G. Partington and M. Peat (2008). Cost of Capital Estimation and Capital Budgeting Practice in Australia, G. Truong, G. Partington and M. Peat. Finance Discipline, School of Business, University of Sydney.	Journal article not to be published
H-5	ECM and EBSS Supplementary Material. Prepared by United Energy Distribution, 28th November 2009.	Journal article not to be published